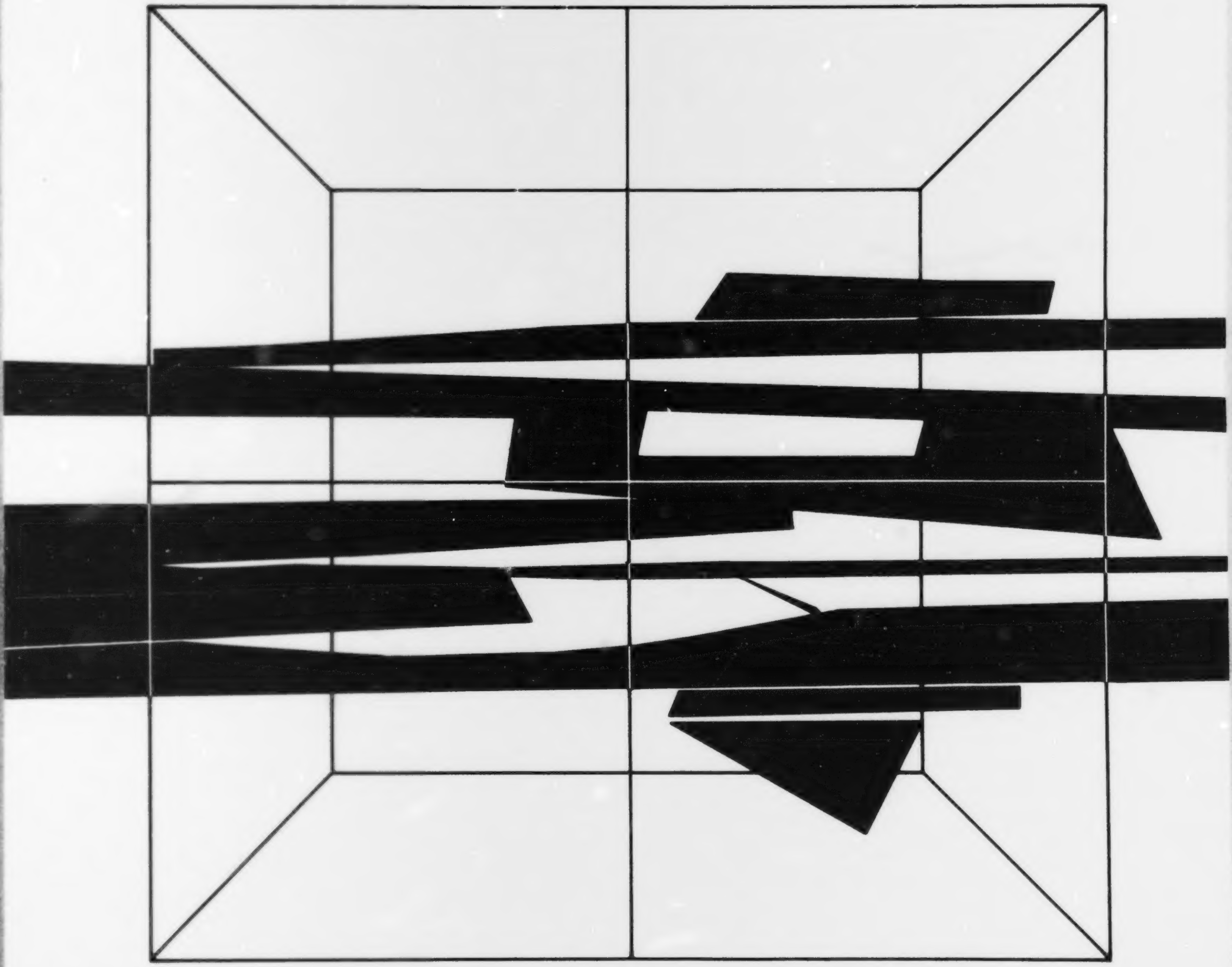
Appendices

Environmental Codes of Practice for Steam Electric Power Generation

Design Phase

Report EPS 1/PG/1A
December 1986



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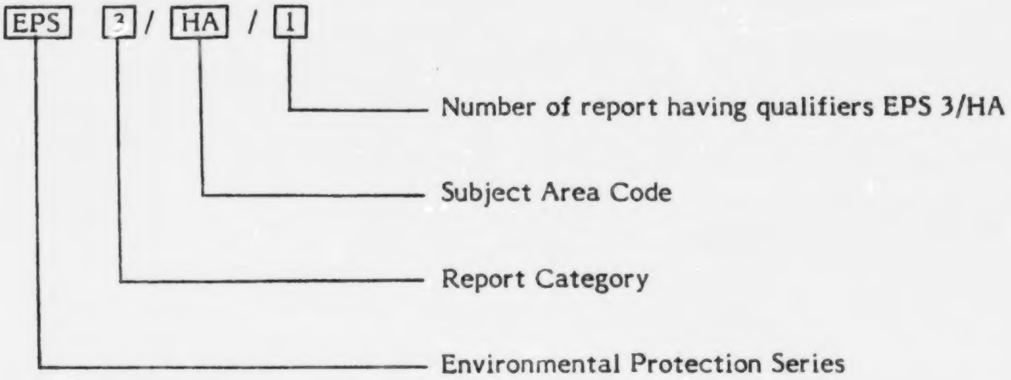
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AP	Airborne Pollutants
AT	Aquatic Toxicity
CC	Commercial Chemicals
CE	Consumers and the Environment
FP	Food Processing
HA	Hazardous Wastes
IC	Inorganic Chemicals
MA	Marine Pollution
MM	Mining & Mineral Processing
NR	Northern Regions
PF	Paper and Fibres
PG	Power Generation
PN	Petroleum and Natural Gas
SP	Oil & Chemical Spills
SRM	Standard Reference Methods
TS	Transportation
UP	Urban Pollution

New subject areas and codes are introduced as they become necessary. A list of EPS reports may be obtained from Environmental Protection Publications, Conservation and Protection, Environment Canada, Ottawa, Ontario, Canada, K1A 0E7.

ENVIRONMENTAL CODES OF PRACTICE
FOR
STEAM ELECTRIC POWER GENERATION

DESIGN PHASE

Industrial Programs Branch
Conservation and Protection
Environment Canada

Report EPS 1/PG/1A
December 1986

NOTICE

For further information, please contact:

D.W. Draper* Chief Oil, Gas and Energy Division, Industrial Programs Branch Conservation and Protection Environment Canada Ottawa, Ontario K1A 0E7 (819) 953-1120	or	P.G. Finlay Head Electric Power Section Industrial Programs Branch Conservation and Protection Environment Canada Ottawa, Ontario K1A 0E7 (819) 953-1126

* Chairman, Task Force, Environmental Codes of Practice for Steam Electric Power Generation

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SUMMARY

S.1 Introduction

The Environmental Codes of Practice for Steam Electric Power Generation consist of a series of documents which will identify good environmental protection practices for various phases of a steam electric power project. These phases include siting, design, construction, operation and decommissioning. The steam electric industry includes fossil-fuelled (coal, oil or gas) and nuclear-powered (CANDU) generating stations. New or modified coal-fuelled and nuclear-powered stations are expected in Canada in the next two decades.

The Environmental Codes of Practice have no legal status. They are an expression of environmental concerns and environmental protection opportunities for new or modified steam electric plants. The Codes are being developed in consultation with a federal-provincial-industry task force. Electric power utilities, various federal and provincial agencies, and the public may use the Codes as sources of technical advice and guidance.

The Design Phase Code, the first of the series of documents, addresses primarily water-related environmental concerns and does not address air emission concerns. However, water and solid waste concerns associated with air pollution control systems are addressed. The Design Phase Code consists of a main document and seven appendices (1).

S.2 Environmental Concerns

The steam electric power generation industry is currently the largest single user of water in Canada (43% of total freshwater withdrawals) and is expected to approximately double its requirements within the next two decades. Large volumes of water, withdrawn from lakes, rivers and oceans, are required to cool condensers and other equipment associated with electricity generation. Much lesser amounts of water are required for process purposes such as make-up for steam production, drinking, laundry, equipment cleaning, ash transportation, etc.

The most biologically productive area of a water body is usually the shallow nearshore zone. Most fish spend some portion of their life cycle in these "littoral" zones because conditions are suitable for spawning, nursery and migration. In large water bodies these littoral zones are small in comparison to the entire water body area and volume. For purposes of Design Phase Code **the nearshore zone is defined as the area between the**

shoreline and the point where the water depth is greater of (i) double the local Secchi disk reading, or (ii) 10 metres.

A "once-through" cooling system for a typical power plant with a shoreline intake may draw in ("entrap") large numbers of aquatic organisms in the form of phytoplankton, zooplankton, fish eggs and larvae, as well as adult fish. The adult fish may be damaged on intake screens ("impingement"). Millions of fish have been impinged during some years at large generating stations. Many more smaller organisms which pass through intake screens and are entrained in the cooling water, may be physically damaged by pumps, piping, etc. In addition, thermal stresses due to temperature rises in the condensers and heat exchangers will damage entrained organisms. The discharge of heated water into the sensitive nearshore zone may also have detrimental effects by changing natural conditions for spawning, incubation, nursery and migration. Fungal and bacterial fish diseases and the growth of "nuisance" aquatic weeds may be promoted.

While the long-term effects on fisheries in various water bodies are uncertain, it is generally agreed that once-through cooling systems may adversely affect the natural ecological health of associated Canadian water bodies. However, available mitigative design measures will help to minimize detrimental effects of once-through cooling systems at any future steam electric site.

Water used for process and service purposes can become contaminated by process chemicals, oil and grease, sanitary wastes, metals and salts leached from ash and coal (at coal-fuelled stations), and radionuclides resulting from fission and neutron activation (at nuclear-powered stations). When natural precipitation (rain and snow) contacts coal piles and ash disposal sites, the seepage and runoff will also become contaminated.

Contaminants in process wastewaters discharged to surface waters may have detrimental effects on biota in the water body. Contaminants in seepage to groundwater are also of concern. Changes in pH (acidic and alkaline), dissolved oxygen, suspended solids and dissolved solids in surface waters may adversely affect the development of fish and other aquatic species. Toxic contaminants may accumulate in aquatic sediments and be biomagnified through the food chain to people. Contaminants in wastewaters discharged to surface waters or to groundwaters could adversely affect water used for irrigation, other industrial processes, recreation, etc., and drinking water supplies for people, livestock and wildlife.

The behaviour and importance of contaminants discharged from steam electric stations will depend, to an extent, on the particular receiving aquatic environment and its uses. However, measures can be incorporated in the design of any new steam electric facility, so that the discharge of these contaminants will be reduced or eliminated.

Large areas of land are required for the disposal of wastes produced by steam electric stations. In particular, coal-fuelled stations use large areas for disposal of ash and flue gas desulphurization wastes. Smaller areas are required for chemical wastes (e.g., water treatment sludges), low level radioactive waste storage, sanitary wastes (sewage treatment sludges) and station garbage. With appropriate provisions made in the design phase, these disposal areas can be reclaimed and reused for parkland, agricultural, residential, industrial or other purposes.

The monitoring of water quantity, water quality, and aquatic biota is important in assessing the environmental protection performance of a station and in verifying the preservation of the environment affected by steam electric facilities. Provisions for monitoring can readily be incorporated during the design phase.

S.3 Recommended Designs and Practices

The major intent of the Design Phase Code is to identify practicable opportunities for the protection of the water and land environments affected by steam electric facilities in one comprehensive document. Environmental protection technologies and practices were identified and assessed on the basis of demonstrated feasibility, reliability, operational impacts and cost implications. Design practices that were considered reasonable and practical have been recommended for new steam electric facilities or for systems which result from modifications to existing stations (e.g., conversion from an oil-fuelled to a coal-fuelled boiler, addition of a flue gas desulphurization system, etc.). Different environmental protection strategies are adopted in the Design Phase Code for once-through cooling water (Type 1 water) and for wastewaters (Type 2 water).

For **once-through cooling water** (which is usually inherently uncontaminated) **the approach is to minimize entrapment of aquatic species; to minimize the physical, thermal and chemical damage to organisms that are entrained in cooling water; and to minimize the detrimental effects of heated discharges.** These recommendations (Series 100) are summarized in Table S.1 and are presented in Section 4.1.1 and Appendix D of the Design Phase Code (1). These recommendations do not apply to recirculating cooling systems (e.g., cooling towers or cooling reservoirs with an annual discharge less than 3 m^3/s per 1000 MWe of installed generating capacity).

For **wastewaters, the approach is to minimize the water volume and amount of contaminants at source; to contain wastewaters in a controlled manner; and to treat**

wastewaters if appropriate. These recommendations (Series 200) are summarized in Table S.2 and are presented in Section 4.2.1 and Appendix E of the Design Phase Code (1).

Recommendations for the design of monitoring facilities for once-through cooling systems, for wastewaters and for groundwaters (Series 300) are summarized in Table S.3 and presented in Section 4.3.1 and Appendix F of the Design Phase Code (1).

Most of the entrainment, entrapment and impingement concerns associated with once-through cooling systems can be virtually eliminated by adopting evaporative cooling systems (i.e. towers or ponds) or possible future dry cooling systems. However, it is assumed that appropriately designed once-through cooling systems, as outlined in the Series 100 recommendations, will provide acceptable environmental protection at many sites, taking into account economic, operational and practical considerations. The Series 100 design recommendations are expected to be complimentary to criteria in the Siting Phase Code which delineates conditions not suitable for once-through cooling systems.

Most of contaminant discharge concerns associated with wastewaters from steam electric power plants, can be eliminated by adopting a "zero discharge" wastewater management strategy. This would reduce water use to less than 5% of a once-through cooling water station, eliminate the discharge of process wastewaters to receiving waters, and virtually eliminate seepage to groundwater by providing secured waste disposal sites. However, it is assumed that appropriately designed wastewater management systems, as outlined in the Series 200 recommendations, will provide acceptable environmental protection at many sites, taking into account water availability and economic, operational and practical considerations.

S.4 General Implications of Recommendations

In general it is much easier and less costly to integrate environmental protection measures in the design of a station, rather than to retrofit remedial measures in stations already constructed and operating when operational and environmental problems become obvious. An objective of the Design Phase Code is to encourage preventive measures during this phase of the project.

S.4.1 Once-Through Cooling Waters. Many of the 16 Series 100 recommendations for the design of once-through cooling systems are interactive. These preventive measures are intended to minimize entrapment and entrainment, damage to entrained organisms and detrimental thermal effects. The major design opportunities identified include:

TABLE S.1 SUMMARY OF RECOMMENDATIONS RELATED TO ONCE-THROUGH COOLING WATER (SERIES 100)

NUMBER	SUBJECT	SUMMARY OF RECOMMENDATION	SECTION/ APPENDIX
Minimization of Quantities of Organisms Entrapped and Entrained			
R101	**Total Cooling Water Withdrawal** - Volume Limitations	Design for less than i) 10% of nearshore zone within 50 km reach, ii) 5% of total volume of lake or reservoir, iii) 10% of average river flow, unless better alternatives are demonstrated.	4.1.1.1 D.4.2
R102	**Auxiliary Cooling Water Withdrawal** - Volume Limitations	Design for i) practical minimum water requirements, ii) practicable reuse of discharge, unless better alternatives are demonstrated.	4.1.1.2 D.4.2
R103	**Cooling Water Pumping System** - Flow Control	Consider i) larger number of smaller pumps, ii) flow control valves for pumps or condensers.	4.1.1.3 D.4.2
R104	**Station Outages** - Scheduling (See R113)	Plan outages for periods of maximum concentration of ichthyoplankton (fish eggs and larvae) entrapped in intake, to extent practicable.	4.1.1.4 D.4.2
R105	**Intake Relative to Shore** - Location	Locate intake offshore beyond nearshore littoral zone, unless better alternatives are demonstrated.	4.1.1.5 D.4.3
R106	**Intake Relative to Outfall** - Locations	Locate intake and outfall i) to minimize recirculation of discharge to intake, ii) so that if inland, intake is longer than outfall, unless better alternatives are demonstrated.	4.1.1.6 D.4.3
R107	**Intake Design** - Selection	Select for offshore submerged intake, a horizontal flow velocity cap design, unless better alternatives are demonstrated.	4.1.1.7 D.4.4
R108	**Shoreline Intake** - Location	Locate i) flush with shoreline, ii) in a shoreline area without protrusions or intrusions.	4.1.1.8 D.4.4
R109	**Intake Design** - Fish Bypass and Flow Criteria	Design for i) installed or retrofit fish by-pass/return, ii) horizontal flow less than 15 cm/s.	4.1.1.9 D.4.4
Minimization of Damage to Organisms Entrapped and Entrained			
R110	**Cooling Water Pumps** - Considerations for Selection	Consider probable physical stresses induced on aquatic organisms by alternative types and numbers of pumps	4.1.1.10 D.5.2
R111	**Biofouling Control** - Alternatives/Design	i) Avoid chemical use if possible. ii) If chemical required, minimize applications. iii) Design application rate control system. iv) Limit application to one condenser at a time during day.	4.1.1.11 D.5.3
R112	**Corrosion, Scaling or Silting Control** - Alternatives/Design	i) Avoid chemical use if possible. ii) If chemicals required, select environmentally innocuous types. iii) Design application rate control system. iv) Consider batch cleaning of condensers/heat exchangers and waste treatment.	4.1.1.12 D.5.3

TABLE 5.1 (Cont'd)

NUMBER	SUBJECT	SUMMARY OF RECOMMENDATION	SECTION/ APPENDIX
Minimization of Detrimental Effects of Heated Discharges			
R113	**Condenser Discharge Temperatures** - Criteria	i) Design for 2°C below lethal temperatures of entrained aquatic species. ii) Minimize flow if aquatic species killed because of physical or chemical stresses. iii) Determine annual temperature rule curve to establish maximum allowable seasonal discharge temperatures.	4.1.1.13 D.5.4
R114	**Thermal Plume Zones** - Limitations to Areas of Influence	Design area of influence (1°C isotherm) for less than i) 10% of nearshore zone within 50 km reach in lake, ii) 10% of nearshore zone within 50 km downstream reach in river, iii) 10% of total surface area of lake or reservoir, iv) 50% of distance across river, lake or reservoir, unless better alternatives are demonstrated.	4.1.1.14 D.6.1
R115	**Outfall** - Location and Design	Design for i) offshore location beyond nearshore zone and directed away from shore, ii) a tunneled discharge to outfall, unless better alternatives are demonstrated.	4.1.1.15 D.6.2
R116	**Supplementary Cooling** - Limitations	Do not use "helper" systems to cool thermal discharges, unless it is demonstrated as best alternative.	4.1.1.16 D.6.3

TABLE S.2 SUMMARY OF RECOMMENDATIONS RELATED TO WASTEWATERS (SERIES 200)

NUMBER	SUBJECT	SUMMARY OF RECOMMENDATION	SECTION/ APPENDIX
Minimization of Contaminants and Wastewater Volumes			
R201	**Evaporative Recirculating Cooling** - Materials of Construction and Chemical Uses	i) Avoid chemical use if possible. ii) Do not use asbestos-based materials in cooling towers. iii) Do not use chromium based compounds in cooling ponds. iv) If chemicals required, design rate control system.	4.2.1.1 E.3.1
R202	**Evaporative Recirculating Cooling** - Design and Operating conditions	Design for i) minimum of two cycles of concentration, ii) so that make-up is through auxiliary coolers, if practicable.	4.2.1.2 E.3.2
R203	**Auxiliary Cooling** - Design	Design for intermediate recirculating loop between once-through cooling water and auxiliary coolers, or use another method to prevent inadvertent contamination.	4.2.1.3 E.3.2
R204	**Ash Handling** - System Selection	Select i) dry fly ash, ii) recirculating bottom ash, unless demonstrated that alternatives will produce less wastewater.	4.2.1.4 E.3.2
R205	**Flue Gas Desulphurization (FGD)** - System Selection/Design	Select system or design system for zero discharge of process wastewater to extent practicable.	4.2.1.5 E.3.2
R206	**Water Reuse** - Design Provisions	If practicable, design for i) reuse of auxiliary cooling discharge, ii) reuse of other wastewaters.	4.2.1.6 E.3.3
R207	**Waste Disposal** - Development and Abandonment	Design ash, FGD and refuse sites for i) modular development during operation, ii) chemical and physical stability suitable for land re-use, iii) site contouring and capping, iv) reclamation prior to abandonment.	4.2.1.7 E.3.4
Containment of Wastewaters and Waste Residues			
R208	**Waste Liquids** - Segregation and Containment	Design for i) containment of all wastewaters, ii) collection of similar wastewaters, iii) separate containments for hazardous wastes, (e.g., PCBs, metal cleaning, radioactive), iv) separate containment for incompatible bulk chemicals.	4.2.1.8 E.4.1
R209	**Containment Facilities** - Sizing Criteria	Design containments for normal volumes of wastewater and i) maximum 24-hour wastewater, ii) maximum spills or leaks, or iii) 100-year 24-hour precipitation event for outside containments.	4.2.1.9 E.4.3a

TABLE S.2 (Cont'd)

NUMBER	SUBJECT	SUMMARY OF RECOMMENDATION	SECTION/ APPENDIX
R210	**Seepage Control** - Permeability Criteria	Ensure that natural or constructed barriers exist between the bottom of the waste disposal site and the underlying aquifer, with minimum flow resistance equivalent to material 1 metre thick, of the following permeabilities: i) 1 x 10^{-7} cm/s for high sulphur (> 1% s) coal piles, chemical and radioactive wastes, ii) 5 x 10^{-7} cm/s for ash and FGD waste lagoons, iii) 1 x 10^{-6} cm/s for low sulphur coal piles (< 1% s), dry ash* and dry FGD waste sites, iv) 1 x 10^{-5} cm/s for other areas. * Except for ash disposal in mines	4.2.1.10 E.4.3b
Treatment of Wastewaters Prior to Discharge			
R211	**Discharged Wastewaters** - Effluent Limitations	Design so that wastewaters discharged to once-through cooling or receiving waters do not exceed following concentrations: pH 6.5 to 9.5 Fe 1.0 mg/L Cr, Cu, Ni, Zn 0.5 mg/L Cr(hexa) 0.05 mg/L TSS 25 mg/L Oil and Grease 15 mg/L TRC 0.2 mg/L	4.2.1.11 E.5.5
R212	**Radioactive Wastewaters** - Management	Consider radioactive wastewater treatment alternatives to further minimize discharge of radionuclides to once-through cooling or receiving waters.	4.2.1.12 E.5.6
R213	**Sanitary Wastewaters** - Treatment	Design for i) segregation from other wastewaters, ii) secondary biological treatment if not directed to a municipal treatment plant.	4.2.1.13 E.5.7

TABLE S.3 SUMMARY OF RECOMMENDATIONS RELATED TO MONITORING (SERIES 300)

NUMBER	SUBJECT	SUMMARY OF RECOMMENDATION	SECTION/ APPENDIX
R301	**Monitoring Facilities** - Access	Design so that they can be safely accessed and used.	4.3.1.1 F.1
R302	**Once-Through Cooling** - Continuous Monitors	Provide for i) continuous flow and temperature monitors and grab sampling of once-through cooling and auxiliary cooling streams, ii) TRC readings at condenser and heat exchangers outlets, if chlorine used.	4.3.1.2 F.2.2
R303	**Once-Through Cooling** - Periodic Monitoring	Provide for periodic biological sampling of cooling water forebay and discharge, and fish by-pass.	4.3.1.3 F.2.2
R304	**Discharged Wastewaters** - Monitors	Provide for i) representative sampling, ii) integrated flow monitors (±10% accuracy), iii) on-line pH, TRC or other monitors.	4.3.1.4 F.3.2
R305	**Inplant Waters** - Monitoring Considerations	Consider flow monitors and sampling facilities for in-plant water streams.	4.3.1.5 F.3.2
R306	**Groundwaters** - Monitors	Provide permanent piezometer/well system at coal storage and waste disposal sites.	4.3.1.6 F.4.2
R307	**Groundwaters** - Pre-operational Monitoring	Conduct pre-operational monitoring starting at least one year before construction.	4.3.1.7 F.4.2
R308	**Aquatic Environment** - Pre-operational Monitoring	Conduct pre-operational monitoring starting at least one year before construction to determine baseline data for biota, water quality and sediment.	4.3.1.8 F.5.3
R309	**Environmental Data** - Processing	Provide appropriate facilities for analyses, alarms, and data storage and retrieval.	4.3.1.9 F.6.2

(i) offshore intake with velocity cap (R105, R101, R107);
(ii) offshore outfall with diffuser directed away from shore (R115, R114);
(iii) fish by-pass and recovery system (R109);
(iv) mechanical condenser and heat exchanger tube cleaning systems (R111, R112);
(v) flow control provisions (R103).

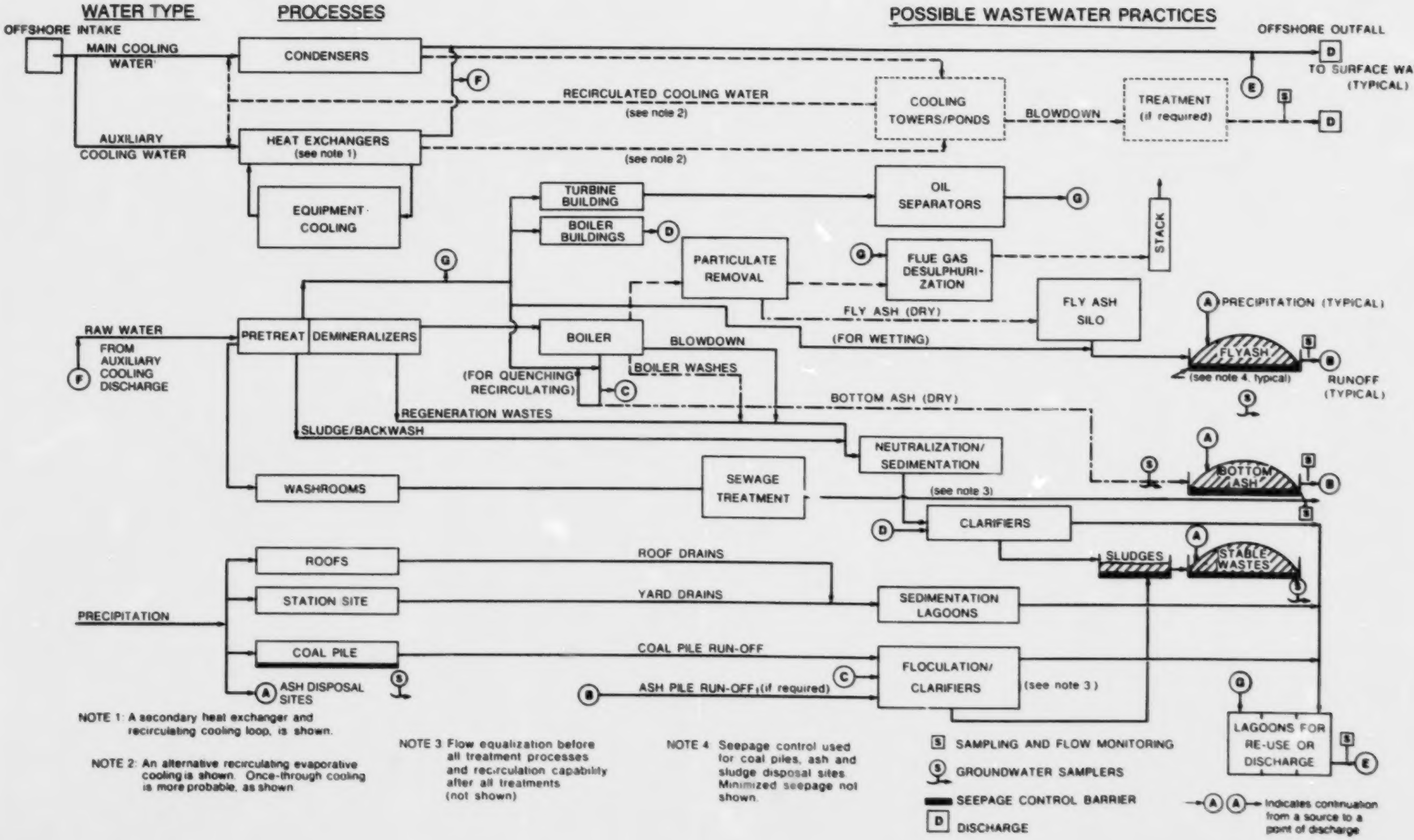
It is expected that, with these design features, most of the other recommendations can be readily achieved with little further provisions.

After the appropriate design provisions of the Series 100 recommendations are made, little associated operations and maintenance attention will be required, except for some fish by-pass systems. In fact, environmentally appropriate designs will reduce probability of forced outages due to intake screen plugging (R107), reduce thermal efficiency losses by minimizing recirculation of heated discharges (R106), and may reduce pumping costs in winter (R103). The incremental energy costs associated with the Series 100 recommendations are very small.

S.4.2 **Wastewaters.** Many of the 13 Series 200 recommendations for the design of wastewater and solid waste management systems, are also interactive. These preventive measures are intended to minimize wastewater volumes and contaminants produced, to contain and control discharge of wastewaters, and to provide wastewater treatment prior to discharge, if appropriate. By considering these aspects in the design phase, and by providing management and treatment facilities for wastewaters of most concern, good environmental protection can be achieved with little additional design, operational or cost impact.

Simplified schematic diagrams of possible water and wastewater management systems are presented for coal-fired stations in Figure S.1 and for CANDU nuclear-powered stations in Figure S.2. Design opportunities identified include:

(i) evaporative recirculating cooling (minimum two cycles of concentration (R202));
(ii) intermediate closed-loop for auxiliary cooling (R203);
(iii) dry fly ash and recirculating bottom ash systems (R204);
(iv) closed-loop flue gas desulphurization system (R205);
(v) reuse of auxiliary cooling water as raw water feed (R206);
(vi) modular development, capping, contouring and reclamation of physically stable waste disposal sites not shown in Figures S.1 and S.2 (R207);
(vii) various containment facilities not shown in Figures S.1 and S.2 (R208, R209);


WATER TYPE
PROCESSES
POSSIBLE WASTEWATER PRACTICES
OFFSHORE INTAKE
MAIN COOLING WATER
AUXILIARY COOLING WATER
CONDENSERS
HEAT EXCHANGERS (see note 1)
EQUIPMENT COOLING
RECIRCULATED COOLING WATER (see note 2)
(see note 2)
COOLING TOWERS/PONDS
BLOWDOWN
TREATMENT (if required)
OFFSHORE OUTFALL
TO SURFACE WATERS (TYPICAL)
TURBINE BUILDING
BOILER BUILDINGS
OIL SEPARATORS
PARTICULATE REMOVAL
FLUE GAS DESULPHURIZATION
STACK
FLY ASH (DRY)
FLY ASH SILO
(FOR WETTING)
PRECIPITATION (TYPICAL)
FLYASH
(see note 4, typical)
RUNOFF (TYPICAL)
RAW WATER
FROM AUXILIARY COOLING DISCHARGE
PRETREAT
DEMINERALIZERS
BOILER
BLOWDOWN
BOILER WASHES
(FOR QUENCHING RECIRCULATING)
BOTTOM ASH (DRY)
REGENERATION WASTES
SLUDGE/BACKWASH
NEUTRALIZATION/ SEDIMENTATION
BOTTOM ASH
WASHROOMS
SEWAGE TREATMENT
(see note 3)
CLARIFIERS
SLUDGES
STABLE WASTES
ROOFS
ROOF DRAINS
STATION SITE
YARD DRAINS
SEDIMENTATION LAGOONS
PRECIPITATION
COAL PILE
COAL PILE RUN-OFF
FLOCULATION/ CLARIFIERS
(see note 3)
ASH DISPOSAL SITES
ASH PILE RUN-OFF (if required)
LAGOONS FOR RE-USE OR DISCHARGE
A
B
C
D
E
F
G
S
S SAMPLING AND FLOW MONITORING
S GROUNDWATER SAMPLERS
SEEPAGE CONTROL BARRIER
D DISCHARGE
A A Indicates continuation from a source to a point of discharge

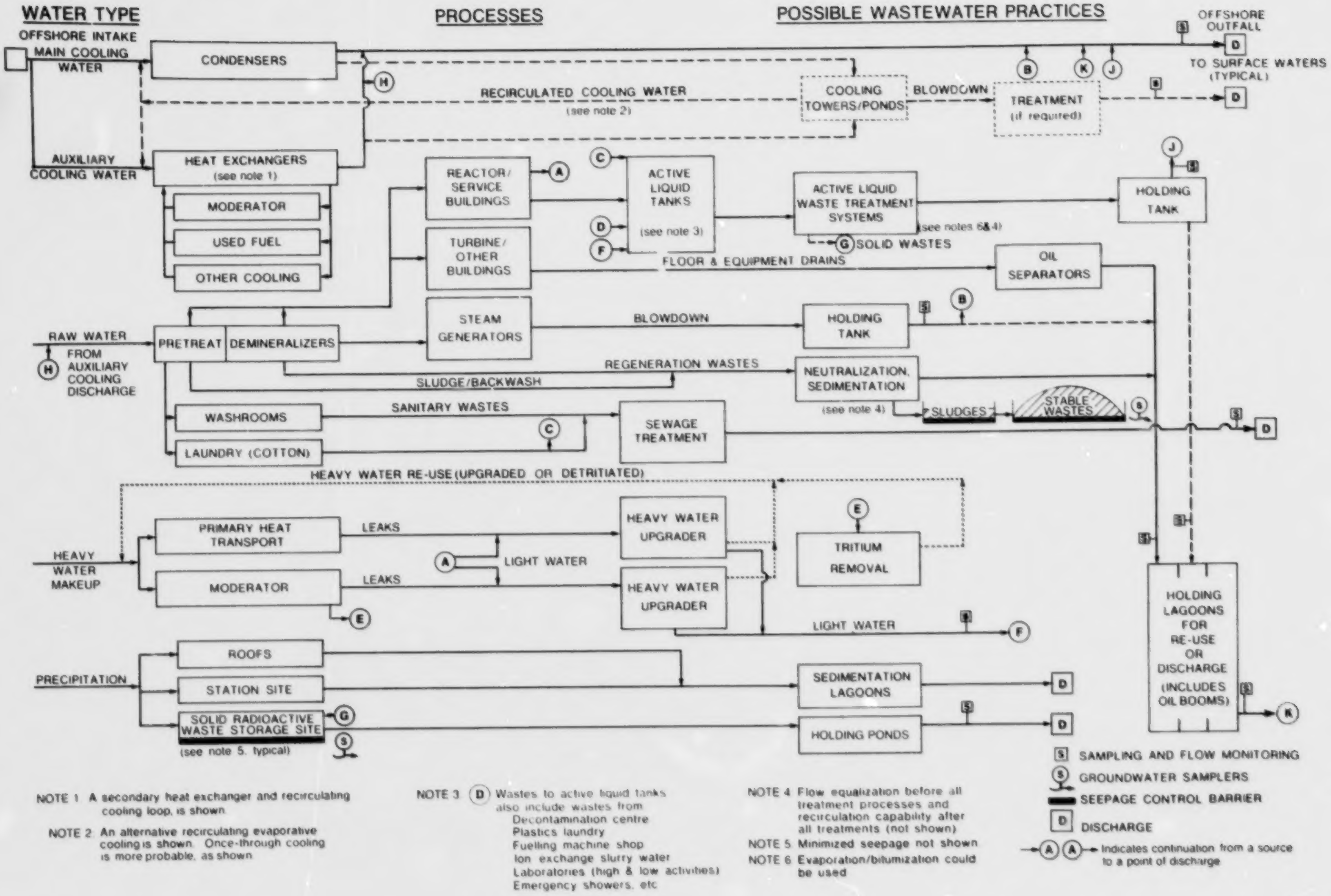
NOTE 1: A secondary heat exchanger and recirculating cooling loop, is shown.

NOTE 2: An alternative recirculating evaporative cooling is shown. Once-through cooling is more probable, as shown.

NOTE 3: Flow equalization before all treatment processes and recirculation capability after all treatments (not shown)

NOTE 4: Seepage control used for coal piles, ash and sludge disposal sites. Minimized seepage not shown.

FIGURE S.1 POSSIBLE WATER AND WASTEWATER SYSTEM SCHEMATIC FOR COAL-FIRED STATIONS


WATER TYPE
PROCESSES
POSSIBLE WASTEWATER PRACTICES
OFFSHORE INTAKE
MAIN COOLING WATER
CONDENSERS
OFFSHORE OUTFALL
TO SURFACE WATERS (TYPICAL)
RECIRCULATED COOLING WATER (see note 2)
COOLING TOWERS/PONDS
BLOWDOWN
TREATMENT (if required)
AUXILIARY COOLING WATER
HEAT EXCHANGERS (see note 1)
MODERATOR
USED FUEL
OTHER COOLING
REACTOR/SERVICE BUILDINGS
ACTIVE LIQUID TANKS (see note 3)
ACTIVE LIQUID WASTE TREATMENT SYSTEMS
(see notes 6&4)
SOLID WASTES
HOLDING TANK
TURBINE/OTHER BUILDINGS
FLOOR & EQUIPMENT DRAINS
OIL SEPARATORS
RAW WATER
FROM AUXILIARY COOLING DISCHARGE
PRETREAT
DEMINERALIZERS
STEAM GENERATORS
BLOWDOWN
HOLDING TANK
REGENERATION WASTES
SLUDGE/BACKWASH
NEUTRALIZATION, SEDIMENTATION
(see note 4)
SLUDGES
STABLE WASTES
WASHROOMS
SANITARY WASTES
LAUNDRY (COTTON)
SEWAGE TREATMENT
HEAVY WATER RE-USE (UPGRADED OR DETRITIATED)
HEAVY WATER MAKEUP
PRIMARY HEAT TRANSPORT
LEAKS
HEAVY WATER UPGRADER
LIGHT WATER
TRITIUM REMOVAL
MODERATOR
LEAKS
HEAVY WATER UPGRADER
LIGHT WATER
HOLDING LAGOONS FOR RE-USE OR DISCHARGE (INCLUDES OIL BOOMS)
PRECIPITATION
ROOFS
STATION SITE
SEDIMENTATION LAGOONS
SOLID RADIOACTIVE WASTE STORAGE SITE
(see note 5. typical)
HOLDING PONDS
A
B
C
D
E
F
G
H
J
K
S
S SAMPLING AND FLOW MONITORING
S GROUNDWATER SAMPLERS
SEEPAGE CONTROL BARRIER
D DISCHARGE
A A Indicates continuation from a source to a point of discharge

NOTE 1 A secondary heat exchanger and recirculating cooling loop, is shown

NOTE 2 An alternative recirculating evaporative cooling is shown. Once-through cooling is more probable, as shown

NOTE 3 (D) Wastes to active liquid tanks also include wastes from
- Decontamination centre
- Plastics laundry
- Fuelling machine shop
- Ion exchange slurry water
- Laboratories (high & low activities)
- Emergency showers, etc

NOTE 4 Flow equalization before all treatment processes and recirculation capability after all treatments (not shown)

NOTE 5 Minimized seepage not shown

NOTE 6 Evaporation/bitumization could be used

FIGURE S.2 POSSIBLE WATER AND WASTEWATER SCHEMATIC FOR CANDU STATIONS

(viii) seepage control for fuel storage and waste disposal sites (R210);

(ix) various treatment systems (R211):

  (a) oil separation for turbine hall drains,
  (b) treatment systems for coal pile runoff, boiler room drains and bottom ash system blowdown,
  (c) sedimentation and oil booms for yard drains.

(x) various radionuclide control systems (R212):

  (a) tritium removal for heavy water,
  (b) treatment system for radioactive wastewaters (e.g., evaporation/fixation).

(xi) secondary sewage treatment (R213).

The most appropriate water and wastewater management system will depend on the raw water quality, the processes of the station, and the judgement of the designers.

After the appropriate design provisions for the Series R200 recommendations are made, the operational implications of many of the recommended designs and practices are insignificant (e.g., containment provisions, seepage control provisions, etc.). However, operational and maintenance attention will be required for the wastewater treatment systems selected. If a "zero discharge" station is designed, a substantial amount of attention will be required to properly operate and maintain the sub-systems. However, this operational disadvantage may be offset in areas where water is scarce or costly.

The incremental energy implications of the recommended designs and practices are expected to be minimal in comparison to the energy requirements of the total station and to the energy requirements associated with air pollution control equipment such as flue gas desulphurization. Relatively small amounts of energy will be required for wastewater pumping and such processes as chemical addition, flocculation, clarification, etc. If evaporators are selected these will also require energy.

S.4.3 Monitoring. The provision of relatively simple and inexpensive monitoring facilities in the design phase will assist subsequent assessments of environmental performance of the station, and will also assist operating staff in optimizing the water and wastewater management systems.

Some possible applications of some of the Series 300 recommendations are indicated in Figures S.1 and S.2. These are flow monitors and representative samplers for wastewater discharges, and samplers for groundwater quality. Other R300 recommendations cannot be readily indicated on these simplified schematics.

The operational implications of the 9 Series 300 recommendations may be significant as plant personnel will be required to sample and analyze various water streams and record flow data. It is suggested that reporting requirements be periodically reviewed with the appropriate environmental agencies. The extent and frequency of reporting may be reduced as operating data and experience is achieved.

The energy and capital cost implications of the Series 300 recommendations are very small in relation to those of the entire station, and to those of the Series 100 and 200 recommendations.

S.5 Cost Implications

Implementing the recommended designs and practices of the Design Phase Code will result in additional costs to power utilities for the construction and operation of new and modified steam electric plants. These incremental costs will be paid ultimately by the consumers of electricity. In order to provide some perspective on the relative magnitude of these costs, cost estimates were prepared and are presented in Section 6 and Appendix G of the Design Phase Code (1). Costs were also estimated for technologies to further reduce radionuclide releases although no specific criteria have been recommended.

"Base case" designs were chosen to represent "worst case" current generating station design and then additional environmental protection design features were assumed to calculate incremental costs that might be attributed to the Design Phase Code recommendations, as shown in Table S.4. It was difficult to establish base cases because many Canadian power plants have design features consistent with a number of those recommended. Some of these features may have been selected for economic and engineering reasons rather than purely environmental considerations (e.g., dry fly ash, intermediate close-loop auxiliary cooling, etc.). Because of this and other conservative assumptions, it is expected that the cost implications have been overestimated. The cost implications to consumers may cover a wider range than shown in Table S.5 because it was assumed that the new generic 1000 MWe stations supplied 25% of the electrical load in each region. Data from an independent unpublished study indicate that the average annual percent increase to the consumer for the cases considered, will vary from 0.002% to 0.279% for new Canadian power plants, from the years 1985 to 2000.

The Design Phase Code recommended practices will contribute to the preservation of the water and land environments affected by future steam electric power generating facilities.

TABLE S.4 MAJOR FEATURES OF ASSUMED GENERIC 1000-MWe STEAM ELECTRIC STATIONS

Model		Major Features
1)	Eastern Canada Coal-fired - with and without FGD* - 5% S, 8% A, 30 MJ/kg**	Once-through cooling, offshore intake and discharge Fish by-pass, dechlorination Intermediate closed-loop auxiliary cooling Dry fly ash, recirculating bottom ash Containments, seepage controls Wastewater treatment, sewage treatment
2)	Central Canada Coal-fired - with and without FGD - 2% S, 10% A, 28 MJ/kg	Evaporative recirculating cooling, dechlorination Intermediate closed-loop auxiliary cooling Dry fly ash, recirculating bottom ash Containments, seepage controls Wastewater treatment, sewage treatment
3)	Eastern/Central Canada Nuclear-powered - with and without RWT***	Once-through cooling, offshore intake and discharge Fish by-pass, dechlorination Intermediate closed-loop auxiliary cooling Conventional wastewater treatment Radioactive wastewater treatment Tritium removal, sewage treatment
4a)	Western Canada Coal-fired - 0.2% S, 15% A, 21 MJ/kg	Evaporative recirculating cooling (base case) Dechlorination Intermediate closed-loop auxiliary cooling Dry fly ash, recirculating bottom ash Containments, seepage controls Wastewater treatment, sewage treatment
4b)	Western Canada Coal-fired - with zero discharge - 0.2% S, 15% A, 21 MJ/kg	Same as 4a) but with wastewater treatment for zero discharge

* FGD - Flue gas desulphurization (FGD required per National Guidelines for New Thermal Generation Emissions)
** S - Sulphur content
A - Ash content
MJ/kg - Average heating value
*** RWT - Radioactive wastewater treatment and tritium removal system

TABLE S.5 ESTIMATED COST IMPLICATIONS OF DESIGN PHASE CODE RECOMMENDATIONS FOR GENERIC 1000 MWe STATIONS

Model	Annual Generation Cost (mills/kWh)	Total Incremental Generation AARR (a) (mills/kWh)	Incremental AARR (a) As Percentage of Annual Generation Cost (%)	Incremental AARR (a) Discounted to 25% (mills/kWh) (b)	Increment In Consumer Rate (c) (%)
To comply with the Design Phase Code Recommendations:					
1) Eastern Canada Coal-fired					
- with FGD (d)	69-133	1.43-3.17	1.1-4.6	0.36-0.79	0.9-2.0
(- without FGD)	62-121	(0.38-1.63)	(0.3-2.6)	(0.10-0.41)	(0.2-1.0)
2) Central Canada Coal-fired					
- with FGD (d)	69-133	1.56-4.03	1.2-5.8	0.39-1.01	1.0-2.5
(- without FGD)	62-121	(0.47-2.74)	(0.4-4.4)	(0.12-0.69)	(0.3-1.7)
3) Eastern/Central Canada Nuclear					
(- with RWT (e))	63-101	(0.80-1.44)	(0.8-2.3)	(0.20-0.36)	(0.5-0.9)
- without RWT	63-101	0.25-0.89	0.3-1.4	0.06-0.22	0.2-0.6
4a) Western Canada Coal-fired	62-121	0.28-1.04	0.2-1.7	0.07-0.26	0.2-0.7
4b) Western Canada Coal-fired					
(- zero discharge)	62-121	(0.70-3.74)	(0.6-6.0)	(0.18-0.94)	(0.4-2.3)

a) AARR = Average Annual Revenue Requirements
b) New generic power plant is assumed to supply 25% of utility's total electrical load
c) Increment in consumer rate calculated on base rate of 40 mills/kWh
d) FGD = Flue Gas Desulphurization (cost of FGD waste management only; FGD required per National Guidelines for New Thermal Generation Emissions)
e) RWT = Radioactive wastewater treatment and tritium removal system (costs shown although not specifically recommended)
f) Zero discharge of process wastewaters (costs shown although not specifically recommended).

ACKNOWLEDGEMENTS

The Environmental Codes of Practice are being developed in consultation and with the assistance of a federal-provincial-industry Task Force. Members of the Task Force were nominated on the basis of their technical interests and expertise. For Environment Canada, in addition to the Environmental Protection Service, the Atmospheric Environment Service and Environmental Conservation Service were represented. Other federal departments and agencies included Fisheries and Oceans Canada, Atomic Energy of Canada Limited and the Atomic Energy Control Board. Members from provincial environmental agencies were nominated by Nova Scotia, Ontario, Manitoba and Alberta, and opportunities to review draft documents were provided to these and other provincial agencies.

Industrial members of the Task Force were nominated by the Canadian Electrical Association. These members were from power utilities in Newfoundland, Nova Scotia, New Brunswick, Prince Edward Island (Maritime Electric), Ontario and Alberta (TransAlta Utilities, Alberta Power and Edmonton Power). Technical reviews of draft documents were also provided by members of power utilities in other provinces through the Environmental Requirements Sub-section of the Canadian Electrical Association. In addition to studies sponsored by Environment Canada, the Canadian Electrical Association has also sponsored studies in areas relevant to the Environmental Codes of Practice.

The Design Phase Code covers a complex and broad area of technical considerations. Members of the Task Force and other reviewers represented a wide spectrum of technical opinion and areas of interest. The assistance, guidance and consultation provided by the many technical contributors has hopefully resulted in a document that reflects what might reasonably be expected of future steam electric facilities in terms of water and solid waste environmental protection measures.

The efforts of the many technical contributors involved, are gratefully acknowledged.

REFERENCE

(1) Environment Canada, "Environmental Codes of Practice for Steam Electric Power Generation, Design Phase Code", Environmental Protection Service, March 1985.

APPENDIX A

TASK FORCE MEMBERS
ENVIRONMENTAL CODES OF PRACTICE
STEAM ELECTRIC POWER GENERATION

TASK FORCE MEMBERS

Federal Government

Allsopp, T.R., Atmospheric Environment Service, Environment Canada

Baket, R.T., Environmental Protection Service, Environment Canada

Chatterjee, R.M., Atomic Energy Control Board

Christensen, R.*, Environmental Protection Service, Environment Canada

Clarke, J.D.*, Atlantic Region, Environmental Protection Service, Environment Canada

Cullen, A.*, Fisheries and Oceans Canada

Day, J., Atlantic Region, Environmental Protection Service, Environment Canada

Dominy, C.L., Fisheries and Oceans Canada

Draper, D.W., Environmental Protection Service, Environment Canada

Dwyer, L.A., Environmental Protection Service, Environment Canada

Finlay, P.G., Environmental Protection Service, Environment Canada

Guilcher, M., Environmental Protection Service, Environment Canada

Hamilton, K.G., Atlantic Region, Environmental Protection Service, Environment Canada

den Hartog, G.*, Atmospheric Environment Service, Environment Canada

Kelso, J.R.M., Fisheries and Oceans Canada

Lark, J.G.I., Fisheries and Oceans Canada

Louie, P.Y.T., Atmospheric Environment Service, Environment Canada

Muir, J.*, Environmental Protection Service, Environment Canada

MacMillan, D.A.G., Environmental Conservation Service, Environment Canada

Murthy, C.R., Environmental Conservation Service, Environment Canada

Park, E.T., Environmental Conservation Service, Environment Canada

Pease, L.*, Atomic Energy of Canada Ltd.

Powell, R.*, Environmental Protection Service, Environment Canada

Ross, G., Environmental Protection Service, Environment Canada

Seibert, G.H., Fisheries and Oceans Canada

Shrives, J.S., Environmental Protection Service, Environment Canada

Snell, V.G., Atomic Energy of Canada Ltd.

Stoddart, R.B.L.*, Fisheries and Oceans Canada

Swiss, J.J.*, Environmental Protection Service, Environment Canada

Vachon, D., Environmental Protection Service, Environment Canada

Vasudev, P., Environmental Protection Service, Environment Canada

Won, T.K.*, Atmospheric Environment Service, Environment Canada

Yaremy, E.M.*, Atomic Energy of Canada Ltd.

---

* Past members

TASK FORCE MEMBERS

Provincial Government

Balcolm, R.*, N.S. Dept. of Environment

Dodge, D.P., Ont. Ministry of Natural Resources

Gotts, R.M., Ont. Ministry of Environment

Hayton, A., Ont. Ministry of Environment

James, A.W., Ont. Ministry of Environment

Johnston, L.M.*, Alta. Dept. of Environment (now Edmonton Power Co.)

MacFarlane, C.*, Ont. Ministry of Environment

Moenig, J.*, Man. Dept. of Consumer and Corporate Affairs and Environment

Moore, L.F.*, Ont. Ministry of Energy

Morelli, M., Man. Dept. of Consumer & Corporate Affairs and Environment

Penttinen, S., Alta. Dept. of Environment

Lethbridge, G.D., N.S. Power

Malvern, B., Ont. Hydro

Rolfe, B.A., Ont. Hydro

Reynolds, J.H., Maritime Electric

Simmons, S.J.*, TransAlta Utilities

Toner, T., N.S. Power

Vivian, G.A., Ont. Hydro

West, A.S.*, Nfld. & Labrador Hydro

Whalen, P.*, N.B. Electric Power

Williamson, F.A., TransAlta Utilities

Power Utilities

Bateson, G.D., TransAlta Utilities

Betancourt, O.J., N.S. Power

Cernavskis, P.*, Ont. Hydro

Deshpande, D., Alta. Power

Doiron, C., N.B. Electric Power

Effer, W.R., Ont. Hydro

Grieve, J.A., Ont. Hydro

Kiell, D., Nfld. and Labrador Hydro

Kolisnyk, Z.*, TransAlta Utilities

LeBlanc, P.J.*, N.S. Power (now Fisheries and Oceans Canada)

LeDrew, B.R.*, Nfld. & Labrador Hydro

---

* Past members

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM-ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 1: PLANNING

Name and Title	Address and Telephone Number
Mr. D.W. Draper (Wayne)* Chief, Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. M. Guilcher (Mike) Chief, Water Pollution Control Air & Water Branch Atlantic Region Environmental Protection Service Environment Canada	5th Floor - Queen's Square 45 Alderney Drive Dartmouth, Nova Scotia B2Y 2H6 (902) 462-6132
Mr. D.A.G. MacMillan (Gerry) Engineering and Development Division Water Planning and Management Branch Inland Waters Directorate Environmental Management Service Environment Canada (PVM - 9th)	Ottawa, Ontario K1A 0E7 (819) 997-2308
Mr. C.L. Dominy (Les) Aquatic Environment Branch Resource Services Directorate Department of Fisheries and Oceans	7th floor West 235 Queen Street Ottawa, Ontario K1A 0E6 (613) 995-4010
Mr. T.R. Allsopp (Terry), Head Climatic Investigations Unit Meteorological Applications Branch Central Service Directorate Atmospheric Environmental Service Environment Canada	4905 Dufferin Street Downsview, Ontario M3H 5T4 (416) 667-4626
Dr. W.R. Effer (Ray) Manager Environmental Studies and Assessments Energy and Environmental Studies Department Ontario Hydro	700 University Avenue Toronto, Ontario M5G 1X6 (416) 592-5202
Mr. A. Hayton (Alan) Water Resources Branch Ontario Ministry of the Environment	1 St. Clair Ave. West Toronto, Ontario M4V 1P5 (416) 965-4590

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM-ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 1: PLANNING (Cont'd)

Name and Title	Address and Telephone Number
Mr. P.G. Finlay (Pat) Head, Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 2: ENVIRONMENTAL OBJECTIVES

Name and Title	Address and Telephone Number
Dr. J.R.M. Kelso (John)* Great Lakes Biological Laboratory Department of Fisheries and Oceans	875 Queen Street East Sault Ste. Marie, Ontario P6A 2B3 (705) 942-2848
Mr. G.H. Seibert Ocean and Aquatic Sciences Department of Fisheries and Oceans	Bedford Institute of Oceanography P.O. Box 1006 Dartmouth, N.S. B2Y 4A2
Mr. D. Kiell Newfoundland and Labrador Hydro	P.O. Box 9100 St. John's, Newfoundland A1A 2X8 (709) 753-8990
Mr. M. Morelli (Max), Chief Environmental Standards & Studies Environmental Management Services Branch Department of Consumer & Corporate Affairs and Environment Province of Manitoba	Box 7, Bldg. 2 139 Tuxedo Avenue Winnipeg, Manitoba R3N 0H6 (204) 945-7032

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 3: SELECTION OF ALTERNATE SITES AND SITE COMPARISON

Name and Title	Address and Telephone Number
Mr. T. Toner (Terry) Environmental Specialist Nova Scotia Power Corporation	P.O. Box 910 Halifax, N.S. B3J 2W5 (902) 424-8503
Mr. T.R. Allsopp (Terry), Head Climatic Investigations Unit Meteorological Applications Branch Central Services Directorate Atmospheric Environment Service Environment Canada	4905 Dufferin Street Downsview, Ontario M3H 5T4 (416) 667-4626
Mr. B. Malvern (Bob) Environmental Studies and Assessment Energy and Environmental Studies Department Ontario Hydro	700 University Avenue Toronto, Ontario M5G 1X6 (416) 592-5202
Mr. J.H. Reynolds (John) General Manager Maritime Electric Limited	P.O. Box 1328 Charlottetown, P.E.I. C1A 7N2 (902) 892-6531
Mr. R. Baker (Bob)*, Senior Biologist Environmental Impact Systems Division External Strategies Branch Environment Protection Service Environment Canada	Ottawa, Ontario K1A 1C8 (819) 997-1731
Mr. F.A. Williamson (Fred) Environmental Planner TransAlta Utilities Corporation	P.O. Box 1900 Calgary, Alberta T2P 2M1 (403) 267-7593
Mr. J.G.I. Lark (John) Senior Freshwater Habitat Biologist Fish Habitat Management Branch Department of Fisheries and Oceans	7th Floor West 240 Sparks Street Ottawa, Ontario K1A 0E6 (613) 995-4010
Mr. L.A. Dwyer (Laurie) Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 4: MONITORING

Name and Title	Address and Telephone Number
Mr. L.A. Dwyer (Laurie)* Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. K.G. Hamilton (Ken) A/Director Air and Water Branch Atlantic Region, Environmental Protection Service Environment Canada	5th Floor - Queen's Square 45 Alderney Drive Dartmouth, Nova Scotia B2Y 2H6 (902) 426-6086
Mr. O.J. Betancourt Senior Advisor - Environment Nova Scotia Power Corporation	P.O. Box 910 Halifax, Nova Scotia B3J 2W5 (902) 424-7890
Mr. C. Doiron (Chris), Supervisor Environmental and Chemical Operations New Brunswick Electric Power Commission	527 King Street Fredericton, New Brunswick E3B 4X2 (506) 453-3021
Mr. G. Ross (Geoff) Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUPS 5 & 6: HEAT GENERATION & STEAM CYCLE & AUXILIARY SYSTEMS

Name and Title	Address and Telephone Number
Mr. K.G. Hamilton (Ken)* A/Director Air and Water Branch Atlantic Region Environmental Protection Service Environment Canada	5th Floor - Queen's Square 45 Alderney Drive Dartmouth, Nova Scotia B2Y 2H6 (902) 426-6086
Mr. J.A. Grieve (John) Technical Superintendant Administration Office (A7-A4) Ontario Hydro	595 Bay Street Toronto, Ontario M5G 2C2 (416) 592-4634
Mr. L.A. Dwyer (Laurie)* Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. C. Doiron (Chris), Supervisor Environmental and Chemival Operations Plan Operation Division New Brunswick Electric Power Commission	527 King Street Fredericton, New Brunswick E3B 4X2 (506) 453-3021
Mr. P.G. Finlay (Pat) Head, Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1200
Mr. G. Ross (Geoff) Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220

---

* Chairmen

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 5B: RADIOACTIVITY

Name and Title	Address and Telephone Number
Dr. V.G. Snell Manager, Risk Assessment and Safety Design Branch Atomic Energy of Canada Limited	Sheridan Park Res. Community Mississauga, Ont. L5K 1B2 (416) 823-9040
Ms. J. Day (Sue) A/District Director Nova Scotia District Atlantic Region Environmental Protection Service Environment Canada	5th Floor - Queen's Square 45 Alderney Drive Dartmouth, Nova Scotia B2Y 2H6 (902) 426-6132
Dr. R.M. Chatterjee (Robi) Radiation Protection Division Directorate of Regulatory Research Atomic Energy Control Board	P.O. Box 1046 Ottawa, Ontario K1P 5S9 (613) 993-7561
Mr. D.W. Draper (Wayne) Chief, Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. R.M. Gotts (Ron) Director Waste Management Branch Ontario Ministry of Environment	135 St. Clair Ave., West Toronto, Ontario M4V 1P5 (416) 965-6191
Mr. A.W. James (Alun) Head, Radioactivity Unit Waste System Planning Section Waste Management Branch Ontario Ministry of Environment	135 St. Clair Avenue West Toronto, Ontario M4V 1P5 (416) 965-6191
Mr. P. Vasudev (Pat) Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. G.A. Vivian (Gary) Assessment, Safety & Program Engineer Nuclear Materials Management Department Design and Development Division Ontario Hydro	700 University Avenue Toronto, Ontario M5G 1X8 (416) 592-5215

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 5B: RADIOACTIVITY (Cont'd)

Name and Title	Address and Telephone Number
Mr. P.G. Finlay (Pat) Head, Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. J.S. Shrives (John) Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 7: ELECTRICAL GENERATION AND TRANSMISSION

Name and Title	Address and Telephone Number
Mr. D.A.G. MacMillan (Gerry)* Engineering and Development Division Water Planning and Management Branch Inland Waters Directorate Environmental Management Service Environment Canada (PVM - 9th)	Ottawa, Ontario K1A 0E7 (819) 997-2308
Mr. L.A. Dwyer (Laurie) Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. B.A. Rolfe (Brian) Electrical Power Systems Engineer Electrical Design Department Design and Development Division Ontario Hydro	700 University Avenue, Toronto, Ontario M5G 1X6 (416) 592-5712

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUPS 8 & 9: ONCE-THROUGH CONDENSER COOLING SYSTEMS INTAKES PUMPS AND CONDENSERS, OUTFALLS AND GENERAL ARRANGEMENTS

Name and Title	Address and Telephone Number
Mr. E.T. Park*, Head, Energy Developments Section, Engineering Division Water Planning and Management Branch Inland Waters Directorate Environmental Management Service Environment Canada (PVM - 9th)	Ottawa, Ontario K1A 0E7 (819) 997-2308
Mr. D.W. Draper (Wayne) Chief, Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Dr. D.P. Dodge (Doug) Supervisor Environmental Dynamics Section Ontario Ministry of Natural Resources	Whitney Block 99 Wellesley Street West Toronto, Ontario M7A 1W3 (416) 965-7887
Mr. J.D. Clarke (John), District Director Newfoundland District Atlantic Region Environmental Protection Service Environment Canada	P.O. Box 5037, 310 Building Pleasantville St. John's, Newfoundland A1C 5V3 (709) 772-5488
Mr. O.J. Betancourt Senior Advisor - Environment Nova Scotia Power Corporation	P.O. Box 910 Halifax, Nova Scotia B3J 2W5 (902) 424-5874

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUPS 10 & 11: CLOSED CYCLE COOLING

Name and Title	Address and Telephone Number
Mr. D. Deshpande (Dilip) Senior Process Engineer Alberta Power Limited	10040-104th Street Edmonton, Alta. T5J 2V6 (403) 420-7177
Mr. D. Vachon (Derek) Wastewater Technology Centre Environment Canada	Wastewater Technology Centre P.O. Box 5050 867 Lakeshore Road Burlington, Ontario L7R 4A6 (416) 637-4558
Mr. P.G. Finlay (Pat)* Head, Electric Power Section Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. P.Y.T. Louie (Paul) Head Hydrometeorological Projects Studies Unit Meteorological Applications Branch Central Services Directorate Atmospheric Environment Service Environment Canada	4905 Dufferin Street Downsview, Ontario M3H 5T4 (416) 667-4521
Mr. G.D. Bateson Power Production Chemical and Environmental, TransAlta Utilities Corp.	110-12th Avenue S.W. Box 1900 Calgary, Alberta T2P 2M1
Mr. L.A. Dwyer (Laurie) Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. S. Penttinen (Stan) Standards and Approvals Division Environmental Protection Services Alberta Department of Environment	Oxbridge Place 9802 - 106 Street Edmonton, Alberta (403) 427-5888

---

* Chairman

TASK FORCE - ENVIRONMENTAL CODES OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION

MEMBERS - WORKING GROUP 12: TEMPERATURE AND HEAT

Name and Title	Address and Telephone Number
Dr. C.R. Murthy Physical Limnology Section Wastewater Technology Centre Environment Canada	P.O. Box 5050 Canada Centre for Inland Waters Burlington, Ontario (416) 637-4235
Mr. D.W. Draper (Wayne)*, Chief Oil, Gas & Energy Division Industrial Programs Branch Environmental Protection Service Environment Canada (PVM - 13th)	Ottawa, Ontario K1A 1C8 (819) 997-1220
Mr. G.D. Lethbridge (Gerry) Vice-President Engineering and Production Nova Scotia Power Corporation	P.O. Box 910 Halifax, Nova Scotia B3J 2W5 (902) 424-7890
Dr. A. Hayton (Alan) Water Resources Branch Ontario Ministry of the Environment	1 St. Clair Ave. West Toronto, Ont. M4V 1P5 (416) 965-4590

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* Chairman

APPENDIX B

ELECTRICAL GENERATION AND WATER USE DATA

TABLE B.1 GENERATING CAPACITY BY FUEL TYPE - CANADA

	1983 Gigawatts	Percent	1990 Gigawatts	Percent	2005 Gigawatts	Percent
Coal	16.4	19	18.4	18	26.0	18
Hydro	50.1	60	58.9	59	86.4	59
Nuclear	7.6	9	13.5	13	22.7	15
Oil & Gas	10.4	12	9.6	10	12.0	8
Total	84.5	100	100.4	100	147.1	100

Source: National Energy Board, "Canadian Energy Supply and Demand 1983-2005", September 1984.

TABLE B.2 ELECTRICITY PRODUCTION BY FUEL TYPE - CANADA

	1983 Terawatt hours	Percent	1990 Terawatt hours	Percent	2005 Terawatt hours	Percent
Coal	68.5	17	75.9	15	99.9	14
Hydro	267.9	68	311.7	62	434.0	62
Nuclear	44.2	11	94.5	19	151.9	22
Oil & Gas	15.4	4	18.2	4	13.5	2
Total	396.0	100	500.3	100	699.3	100

Source: National Energy Board, "Canadian Energy Supply and Demand 1983-2005", September 1984.

TABLE B.3 STEAM ELECTRIC CAPACITY BY PROVINCE, EXISTING CAPACITY FOR 1983 NEW CAPACITY FOR 1984 TO 2000

		CAPACITY (MWe), and Number of Locations( )				
Province	Year	Coal	Oil	Gas	Nuclear	Total
Newfoundland	2000*	-	-	-	-	0
	1983*	0(0)	480(2)	0(0)	0(0)	480(2)
Nova Scotia	2000	1 947(3)	-	-	-	1 947(3)
	1983	577(4)	577(2)	0(0)	0(0)	1 124(6)
Prince Edward Island	2000	-	-	-	-	0
	1983	0(0)	69(1)	0(0)	0(0)	69(1)
New Brunswick	2000	200(1)	-	-	600(1)	800(2)
	1983	315(3)	1 383(3)	0(0)	600(1)	2 298(7)
Québec	2000	-	-	-	-	0
	1983	0(0)	600(1)	0(0)	600(1)	1 200(2)
Ontario	2000	206(1)	-	-	9 075(3)	9 281(4)
	1983	9 530(6)	0(0)	0(0)	6 040(5)	15 570(11)
Manitoba	2000	-	-	-	-	0
	1983	369(2)	0(0)	0(0)	0(0)	369(2)
Saskatchewan	2000	560(1)	-	-	-	560(1)
	1983	1 682(4)	0(0)	362(2)	0(0)	2 044(6)
Alberta	2000	7 950(8)	-	-	-	7 950(8)
	1983	3 785(5)	0(0)	935(2)	0(0)	4 720(7)
British Columbia	2000	-	-	-	-	-
	1983	0(0)	0(0)	912(1)	0(0)	912(1)
Yukon	2000	-	-	-	-	0
	1983	0(0)	0(0)	0(0)	0(0)	0(0)
Northwest Territories	2000	-	-	-	-	0
	1983	0(0)	0(0)	0(0)	0(0)	0(0)
Canada	2000	10 863(14)	0(0)	0(0)	9 675(4)	20 538(18)
	1983	16 228(24)	3 109(9)	2 209(5)	7 240(7)	28 786(45)

*1983 indicates steam electric capacity available in 1983.
2000 indicates new steam electric capacity projected to be available between 1984 and 2000.

Derived from: Monserco Ltd., "Forecasting Steam-Electric Power Generation in Canada over the Period of 1983-2035", for Environment Canada, May 1983.

TABLE B.4 ESTIMATED CURRENT AND FUTURE WATER WITHDRAWAL USE BY ENERGY AND NON-ENERGY INDUSTRIES FOR 1) CANADA AND 2) PRAIRIE PROVINCES (1980-2020)

	1980		2000		2020	
	ML/d	%	ML/d	%	ML/d	%
1) CANADA						
Energy Uses						
Thermal Generation[a]	48 400	43.4	143 400	58.9	397 900	74.1
Other Energy Uses	4 443	4.0	7 019	2.9	9 174	1.7
Sub-Total	52 843	47.4	150 419	61.8	407 074	75.8
Non-Energy Uses[b]	58 862	52.6	93 200	38.2	130 200	24.2
Total	111 705	100.0	243 619	100.0	537 274	100.0
2) PRAIRIE REGION						
Energy Uses						
Thermal Generation[a]	5 557	37.5	14 060	46.6	26 000	52.1
Other Energy Uses	753	5.1	1 091	3.6	1 488	3.0
Sub-Total	6 310	42.6	15 151	50.2	27 488	55.1
Non-Energy Uses[b]	8 477	57.4	14 995	49.8	22 380	44.9
Total	14 787	100.0	30 146	100.0	49 868	100.0

(a) Includes water used to manufacture heavy water. Allowance has been made for increased use of closed condenser cooling systems.

(b) Municipal manufacturing, rural domestic and agricultural water usage only.

Source: Environment Canada, "Canadian Water Year Book 1981-82, Water and the Economy", Canadian Government Publishing Centre, 1983.

APPENDIX C

SELECTED ENVIRONMENTAL OBJECTIVES, SELECTED WATER QUALITY CRITERIA, THERMAL POWER GENERATION EMISSIONS - NATIONAL GUIDELINES FOR NEW STATIONARY SOURCES, AND FEDERAL REGULATION OF CHLOROBIPHENYLS (PCB's)

APPENDIX C

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C. SELECTED ENVIRONMENTAL OBJECTIVES

C.1 Introduction

The environmental objectives herein discussed are included in the Environmental Codes of Practice as criteria and methodologies that may assist on a site-specific basis to assess the effectiveness of the national baseline control requirements outlined in the codes and Appendices D and E of this code. In general, they would be used to determine whether controls more stringent than the baseline are needed to ensure adequate protection of the environment. However, there are also cases where provision is made in the baseline recommendations for relaxation of standards or use of a design feature other than that specified, if it can be clearly demonstrated that an alternate control measure or design option will provide as good or better protection to the environment. The environmental objectives can be used as a guide to the kinds of criteria and methodologies that might be used in demonstrating the suitability of such alternatives.

C.2 Environmental Objectives for the Protection of Water Quality

C.2.1 Chemical Elements. Water quality objectives are minimum desirable levels designed to protect aquatic ecosystems for the most sensitive use among the spectrum of common uses of water: recreation, aesthetic enjoyment, the propagation of aquatic life and wildlife, supplies for municipal, industrial and agricultural purposes. The recommended objective is normally based on the protection of aquatic life, with protection of public water supply also frequently selected.

Environmental objectives to safeguard the range of water uses are distinct from standards, guidelines, regulations, treatment controls or other methods of achieving suitable water for the variety of uses. Water quality objectives (in this case synonymous with environmental objectives) are scientifically based recommendations (numerical or descriptive) protecting the most sensitive use. These serve as the precursor to a standard or regulation as well as a benchmark against which the effectiveness of the control measure can be compared. Environmental objectives are not generally used directly as control mechanisms. However with control imposed by the application of best practicable technology for example, the objectives can serve to identify instances where baseline technology is inadequate or, generally, where more stringent control is required.

Specific environmental objectives are provided in Table C.1. It should be noted that although the objectives in Table C.1 are proposed for steam electric stations, they are applicable to any and all activities that can affect the aquatic environment. Objectives reflect the knowledge and state-of-the-art at a particular time. No attempt has been made here to develop new objectives or assess whether experiments conducted within recent years demand modification of previously accepted objectives. Objectives presented in Table C.1 are extracted from pre-1977 documents. As advocated by the International Joint Commission (IJC) (1975), they represent a minimum quality of water which will not only provide for, but protect the designated use. For more current information the reader is referred to the Inventory of Water Quality Guidelines and Objectives prepared by the Canadian Council of Resource and Environment Ministers (CCREM) (1985).

As with objectives promulgated by the IJC (1975) and U.S. Environmental Protection Agency (EPA) (1973), the proposed environmental objectives should be implemented in concert with limitations on the acceptable extent of a mixing zone or zone of influence at a particular site. If environmental objectives and mixing zones are applied together, a management tool for assessing or establishing the adequacy of controls then becomes available. Since mixing zone criteria have been only generally defined (Appendix D), the utility of environmental objectives is generally confined to identifying and establishing the status of aquatic systems and determining whether the standards and/or control technology has been adequate. To date mixing zones have usually been approached on a case-by-case basis by the provincial authority involved. In such cases the general recommendations provided in Section C.2.3 are applied. No matter how environmental objectives are used, they should not be construed as goals in themselves.

For further reference, a summary of selected guidelines for water quality parameters has been included at the end of this appendix.

An inadequate data base exists to permit the establishment of a scientically justifiable numerical objective for complex wastes and unspecified toxic substances. To provide a guideline that should permit at least a reasonable degree of protection from such materials, the following procedural objective is proposed:

> Unspecified non-persistent toxic substances and complex wastes should not be present in concentrations that exceed 5% of the lethal concentration (96-h LC_{50}) for any approved test species.

This procedural objective is proposed to protect aquatic life against adverse effects from complex effluents or compounds (elements).

TABLE C.1 ENVIRONMENTAL OBJECTIVES (Compiled in 1979)

Parameter	Objective	Comment	Source
Flotsam	zero	maintain aesthetic quality and preserve aquatic system	Env. Can., 1972; IJC, 1975
Oil, grease, scum immiscible substances	zero	env. effects imperfectly known	U.S. EPA, 1973; IJC 1975; Env. Can., 1972
Total dissolved solids	to be used largely as a monitoring tool	TDS alone is not detrimental unless very high concentrations reached	IJC, 1975
Settleable and suspended materials	zero	protects aquatic system	Env. Can., 1972; IJC, 1975
pH	pH 6.5-9.0 (no change from ambient 0.5 units)	related to toxicity of other contaminants and well being of the system	OME, 1974; U.S. EPA, 1973; IJC, 1975
Alkalinity	changes must be 25% of natural levels	avoids alteration of buffering capacity	U.S. EPA, 1973; Env. Can., 1972
Chlorine	should not exceed 0.05 mg/L for up to 30 min. (0.002 mg/L to protect trout and fish food organisms) should not exceed 0.01 mg/L in marine waters		IJC, 1975; U.S. EPA, 1973
Total Dissolved Gases	not to exceed 110% of saturation	to avoid supersaturation stresses	U.S. EPA, 1973
Dissolved oxygen	not less than 6 mg/L and not less than $1.41 M - 0.0476 M^2 - 1.11$ (where M = natural seasonal minimum concentration)	to ensure adequate oxygen for respiration and limit organic loading	U.S. EPA, 1973; IJC, 1975
Carbon dioxide		conc. 20 mg/L rarely occurs	
Hydrogen sulphide	not to exceed 0.002 mg/L	is pH dependent and toxic to aquatic life	U.S. EPA, 1973 & 1976
Phosphorus	no change from ambient	in general P conc. should be limited to the extent necessary to prevent nuisance conditions	IJC, 1975
Polychlorinated Biphenyls	in fish tissues should not exceed 0.1 µg/g	to protect fish-consuming birds and animals	IJC, 1975

TABLE C.1 ENVIRONMENTAL OBJECTIVES (Compiled in 1979) (Cont'd)

Parameter	Objective		Comment	Source
Nitrogen: nitrite nitrate	maintenance of background nitrogen to phosphorus ratio			
Ammonia	ionized ammonia should not exceed 0.020 mg/L		protect aquatic life	
	total ammonia should not exceed 0.5 mg/L		protect public water supply	
Aluminum	0.1 mg/L		to protect aquatic life	IJC, 1975
Antimony	0.2 mg/L			MAN., 1976
Arsenic	$0.05^{a,d}$ mg/L		to protect drinking water supplies	IJC, 1975
Barium	$0.5^{c,d}$ mg/L			MAN., 1976
Beryllium	soft water 0.011 mg/L		hard water 1.1	U.S. EPA, 1976
Boron	c			
Cadmium	soft water (mg/L)	hard water[a] (mg/L)		
	0.0004	0.0012	cladocerans & salmonids	U.S. EPA, 1976
	0.0040	0.0120	other less sensitive organisms	
Chromium	0.1 mg/L			U.S. EPA, 1976
Cobalt	c			
Copper	0.1 x 96-h $LC_{50}^{b,f}$			U.S. EPA, 1976
Fluoride	should not exceed 1.0 mg/L		to protect public water supplies and aquatic life	IJC, 1975
Iron	1.0^{b} mg/L			U.S. EPA, 1976
Lead	0.01 x 96-h $LC_{50}^{a,f}$			IJC, 1975
Magnesium	e			
Manganese	$0.05^{c,d}$ mg/L			U.S. EPA, 1976

TABLE C.1 ENVIRONMENTAL OBJECTIVES (Compiled in 1979) (Cont'd)

Parameter	Objective	Comment	Source
Mercury	0.00005[a] mg/L		U.S. EPA, 1976
Molybdenum	c		
Nickel	0.01 x 96-h LC_{50}[b,f]		U.S. EPA, 1976
Selenium	0.02 x 96-h LC_{50}[a,b,f]	to protect aquatic life	IJC, 1975
Silver	0.0001 mg/L		IJC, 1975
Sodium			
Thallium	0.05		MAN., 1976
Tin	e		
Titanium	e		
Uranium	0.1 mg/L		MAN., 1976
Vanadium	c		
Zinc	0.01 x 96-h LC_{50}[a,f]		U.S. EPA, 1976

a Parameters and objectives revised during 1976 by IJC, but not included here.
b Parameters and objectives revised during 1977 by IJC, but not included here.
c Parameters and objectives were being revised by IJC.
d Objective for public water supplies only, not for the protection of aquatic life.
e No existing objectives.
f Determined through standard acceptable bioassay technique utilizing a sensitive resident species as the test organism and the receiving water (or a comparable water) as the diluent.

To ensure that aquatic life in receiving waters is afforded adequate protection it is necessary to establish the toxicity of these substances. The toxicity of individual substances or mixtures must be further evaluated by the use of an application factor to reduce conditions from chronic to non-lethal levels. The use of an application factor will not necessarily preclude sublethal conditions. Where effects outside established mixing zones are demonstrated, the application factor is inadequate. The choice of an application factor is based on recommendations (U.S. EPA, 1973) for determining acceptable concentrations when toxicological data are lacking.

An appropriate test species would be any sensitive, locally important species or specific life history stage of that species as selected by the regulatory agency. Alternatively any species which has successfully been used in toxicity tests representative of the water body in question could be chosen. Appropriate testing procedures are described fully by the APHA, AWWA, and WPCF (1975).

The IJC (1978) recognized the limitations of a water quality approach to aquatic ecosystems and pointed out that the problem with the methods proposed above is that once objectives are exceeded, it is "too late" for the system. The application of environmental objectives at the boundary of mixing zones, and effluent controls or the imposition of technology designated as providing appropriate treatment, are by themselves inadequate means of diagnosing, preventing and curing aquatic environmental problems. The use of the "ecosystem approach" in conjunction with objectives (IJC, 1978) will assist in meeting these needs.

C.2.2 Temperature. The normal contribution of heat to aquatic systems is essentially through solar radiation but when that contribution is augmented by increasing development of urban and industrial complexes requiring cooling water, the potential for alteration of thermal structure - local or system-wide - becomes of concern. Thermal effects from the steam electric generation process can best be reduced through restrictions applied to events occurring in-plant, in the near field and in the far field.

(i) In-Plant Effects - Passive and active biotic forms are vulnerable to most thermal effects but it is the passive biota, particularly those that become entrained, that suffer most. Detrimental effects of thermal exposure during entrainment can be judged using the following equation (see NAS/NAE, 1973, for full details):

$$\frac{\text{time}}{10^{(a + b(\text{temp} + 2))}} < 1 \qquad (1)$$

where time is the exposure time, temp is the discharge temperature, and a and b are derived from the equation relating incipient lethal temperature to acclimation temperature for a specific species. It is recommended that:

> The discharge temperature for condenser cooling systems should not exceed a value that will cause the left-hand side of equation (1) to exceed unity.

In Canada in general, and on the Great Lakes in particular, power plants have short discharge canals; consequently, the critical "time" is generally less than five minutes. As a result, the equation provides an upper threshold for temperature at which no mortality will occurr. As an example:

(i) In the spring, when rainbow trout are present and the ambient (acclimation) temperature is 10°C at Douglas Point, time is estimated at three minutes, a = 14.6405, and b = -0.447.

$$1 > \frac{3}{10^{(14.6405 - 0.447\,(\text{temp} + 2))}}$$

By solution of the equation, temperature must be less than 29.7°C or temperature rise above ambient must be less than 19.7°C.

(ii) In the summer when trout are no longer resident and smallmouth bass are the most important sensitive species, ambient temperature is 20°C at Douglas Point. "Time" is still three minutes, a = 34.3649, and b = -0.9789 (assumed as *Micropterus salmoides*).

$$1 > \frac{3}{10^{(34.3649 - 0.9789\,(\text{temp} + 2))}}$$

By solution of the equation, temperature must be less than 32.6°C or temperature rise above ambient must be less than 12.6°C.

The temperature limits determined by equation (1) ensure protection of entrained biota against direct mortality resulting from temperature during the severest conditions attributable to use of water for condenser cooling. However, its use is based upon the assumption that at least a portion of the entrained biota is not already destroyed by physical stresses in passage through the cooling system. If it is determined that a portion of the entrained organisms will survive the imposed physical stresses, the cooling system should be operated near the maximum temperature computed by equation (1) to ensure minimum flow.

The application of the limitation described by equation (1) to all North American marine or freshwater systems is hampered by the availability of time-temperature response (a and b in the equation) data. Available data have been summarized by NAS/NAE (1973). The concept includes the fact that a constant rise above ambient (ΔT) will not be appropriate for all times of year since neither acclimation (ambient) temperatures nor important species remain constant. To assume that these variables are in fact invariable endangers the integrity of the aquatic ecosystem. Hence, adjustments to the annual rule curves prescribed as baseline temperature control may be required on a site-specific basis to ensure protection is afforded during all periods of the year to the species of concern (see Appendix D.5.4).

(ii) Near Field Effects - Mobile organisms demonstrate varying degrees of habitat preference. For these organisms, the end result of a shift in temperature, upward or downward, depends upon species in the community and acclimatization.

For fish, the length of time that 50% of a population will survive temperatures above the upper incipient lethal temperature can be calculated using: log (time) = a + b (temp). This relation was used in deriving equation (1) and the application of equation (1) ensures survival from high temperatures anywhere in the receiving water body.

On the other hand, to prevent mortality from "cold shock", temperatures should not exceed the temperature from which the most sensitive important species die when that temperature is returned to ambient with the upper limit being the acclimation temperature (plume temperature), minus a 2°C safety factor. This objective is only relevant to power plants having few thermal generating units and/or used specifically in a peaking capacity.

Generally, the association of fish with discharge canals or areas of turbulent mixing is short-lived unless no other suitable habitat is available. The response is based in large part on their temperature preference and reaction to current (Neill and Magnuson 1974; Coutant 1975; Kelso 1974, 1976). The foregoing method for establishing temperature limits ensures that no direct mortality due to temperature occurs and that loss of habitat for spawning and rearing is minimal.

(iii) Far Field Effects - Biota in any body of water, or a portion of it, survive with varying degrees of success depending upon the habitat characteristics. Since temperature is a major influencing factor for each habitat, wholesale alteration in temperature can disturb natural balances. To generally protect the integrity of an aquatic ecosystem, the following objective should apply except to man-made cooling ponds or systems written off as cooling water bodies:

> Thermal additions to receiving waters or a designated segment thereof should be such that thermal stratification and subsequent turnover dates are not altered beyond the norm existing prior to addition of heat of artificial origin.

The above objective recognizes that some aquatic ecosystems (small lakes, reservoirs, systems with limited circulation or stability) or portions of them (primarily bays, sheltered areas, regions of restricted water mass movement) do not have the capacity to sustain wholesale alterations in temperature without irretrievable changes. Since no method currently exists to mathematically describe a "typical" thermal regime, the basic assumption is that if a system-wide (or contained segment) change occurs, an unfavourable alteration of the equilibrium of the aquatic system will occur.

(iv) General Discussion and Summary - The above objectives recognize the controlling effect of temperature upon the physical behaviour of aquatic ecosystems and their biota. They recognize the concern raised regarding "waste heat" effects but these objectives alone will not prevent the degradation of waters (systems) used for cooling purposes.

During entrainment, pressure and physical perturbations kill the passive biota that are caught up in cooling waters. Further, mobile forms can impinge upon screens in the intake facility. These direct mortalities must be dealt with either through guidelines for siting designed to minimize the numbers entrained and impinged, or through a guideline designed to establish an upper limit to the numbers entrained or impinged, or both.

Further, the objectives recognize several major areas of effect, namely: the intake process, condenser cooling system, discharge and contiguous area of turbulent mixing (near field). The plume established when currents of cooling waters approach ambient has little direct effect upon organisms (Kelso, 1974, 1976; Kelso and Minns, 1975; Coutant, 1975; Neill and Magnuson, 1974) unless the plume impinges upon the shoreline, is joined by other thermal plumes or exacerbates discharges from other sources. To limit these problems and to ensure that the loss of habitat to near field effects is contained in acceptable limits, mixing zones should be considered.

In conclusion, the proposed objectives will ensure adequate environmental protection only when combined with mechanisms to ensure appropriate siting, acceptable levels of entrainment and impingement mortality, and intelligent designation of mixing zones.

C.2.3 Mixing Zones. The following non-numerical guidelines for the treatment of mixing zones are from the IJC (1975) and U.S. EPA (1973)):

(i) A mixing zone, is an area contiguous to a point source discharge where exceptions to water quality objectives exist.

(ii) Limitations to mixing zones should be established by the regulatory agency on a case-by-case basis where not only local considerations are examined but also the implications to the water body as a whole.

(iii) Although mixing zones do not meet water quality objectives, conditions should not:

- a) be rapidly lethal to important aquatic life, either resident or transient;
- b) cause irreversible responses which could result in post-exposure death or loss of important function;
- c) result in bioconcentration of materials which are harmful to the organism or its consumer;
- d) introduce substances or create conditions which produce aquatic life in nuisance quantities that interfere with other uses;
- e) introduce substances or create conditions resulting in objectionable colour, odour or taste.

(iv) Mixing zones should not form a barrier to the normal passage of aquatic species and, in biotic environments, should not occupy more than 1/3 of the width.

(v) Overlapping of mixing zones is appropriate unless the combined effects exceed recommendations above.

(vi) Mixing zones should not be permitted in areas of extraordinary value to the aquatic system, e.g., fish spawning beds or aquatic macrophyte beds serving as nurture areas for important aquatic species.

(vii) Existing biological, chemical, physical and hydrological conditions should be known when considering a new mixing zone or prescribing physical limits to an existing one.

(viii) While mixing zones should not be lethal, should not interfere with passage and should not generally be debilitating to biota or the ecosystem in general, the thoughtful placement of the discharge and knowledge and/or control of plume behaviour can increase the level of ecosystem protection.

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SELECTED GUIDELINES FOR WATER QUALITY PARAMETERS

PARAMETERS	UNITS	RECREATIONAL WATERS G	MARINE AQUATIC LIFE MINIMAL RISK G OF ADVERSE EFFECTS	MARINE AQUATIC LIFE PROTECTION G	FRESHWATER AQUATIC LIFE PROTECTION G	IRRIGATION OF ACIDIC SOILS CONTINUOUS USE ALL SOILS G	IRRIGATION OF FINE TEXTURED ALKALINE SOILS G	LIVESTOCK AND WILDLIFE WATERING G	CHEMICAL AND ALLIED INDUSTRIES G	DRINKING WATER MAC	DRINKING WATER O	ELECTRICAL UTILITIES HIGH PRESSURE STEAM GENERATION G	STEAM ELECTRIC WASTEWATER DISCHARGE (2)
GENERAL (1)													
pH		>6 <9		≥6.5 ≤8.5	≥6.5 ≤9.0	≥4.5 ≤9.0	≥4.5 ≤9.0		≥6.5 ≤8.5	≥6.5 ≤8.5		≥8.8 ≤9.4	≥6.5 ≤9.5
SPECIFIC CONDUCTANCE	µmhos/cm												
TOTAL SOLIDS	mg/L												
TOTAL SUSPENDED SOLIDS	mg/L				≤25				≤15			≤0.05	≤25.0
TOTAL DISSOLVED SOLIDS	mg/L					≤500	≤500	≤2500	≤750	≤500		≤0.5	
TURBIDITY	NTU	≤50								≤5	<1		
CHEMICAL OXYGEN DEMAND	mg/L											≤1.0	
DISSOLVED OXYGEN	mg/L				≥4.0							≤0.007	
ANIONS (1)													
OH ALKALINITY AS $CaCO_3$	mg/L				>20				≤150	≥30 ≤500		≤1	
SULPHATE AS SO_4	mg/L							≤1000	≤250	≤500	<150		
SULPHITE AS SO_3	mg/L												
TOTAL RESIDUAL CHLORINE	mg/L												≤0.5* ≤0.2**
CHLORIDE	mg/L					≤150	≤150		≤250	≤250	<250		
FLOURIDE	mg/L		<0.5			≤1.0	≤15.0	≤2.0		≤1.5	≤1.0		
ORTHOPHOSPHATE AS PO_4	mg/L												
PHOSPHATE, TOTAL, AS P	mg/L				<0.025					<0.100			
RADIOACTIVITY AND RADIONUCLIDES (CANADA) (3)													
GROSS α	Bq/L	<0.37				≤0.02	≤0.02	≤0.02		≤0.1			
GROSS β	Bq/L					≤0.19	≤0.19	≤0.19		≤1.0			
CESIUM-137	Bq/L									≤50	≤5		
IODINE-131	Bq/L									≤10	≤1		
RADIUM-226	Bq/L									≤1.0	≤0.1		
STRONTIUM-90	Bq/L									≤10	≤1		
TRITIUM	Bq/L									≤40000	≤4000		

SYMBOLS USED

G-GUIDE LINES
O-OBJECTIVES OR TARGET CONCENTRATIONS
MAC-MAXIMUM ACCEPTABLE CONCENTRATIONS
*-ONCE-THROUGH COOLING AT CONDENSER DISCHARGE
**-RECIRCULATING COOLING BLOWDOWN

(1) DERIVED FROM "WATER QUALITY SOURCEBOOK - A GUIDE TO WATER QUALITY PARAMETERS", 1979, ENVIRONMENT CANADA, UNLESS OTHERWISE NOTED.

(2) WASTEWATER EFFLUENT QUALITY RECOMMENDED IN THE DESIGN PHASE ENVIRONMENTAL CODE OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION.

(3) GROSS α AND β VALUES FOR DRINKING WATER DERIVED FROM "GUIDELINES FOR CANADIAN DRINKING WATER QUALITY", 1978, HEALTH AND WELFARE CANADA.

SELECTED GUIDELINES FOR WATER QUALITY PARAMETERS

PARAMETERS	UNITS	RECREATIONAL WATERS G	MARINE AQUATIC LIFE MINIMAL RISK G OF ADVERSE EFFECTS	MARINE AQUATIC LIFE PROTECTION G	FRESHWATER AQUATIC LIFE PROTECTION G	IRRIGATION OF ACIDIC SOILS CONTINUOUS USE ALL SOILS G	IRRIGATION OF FINE TEXTURED ALKALINE SOILS G	LIVESTOCK AND WILDLIFE WATERING G	CHEMICAL AND ALLIED INDUSTRIES G	DRINKING WATER MAC	DRINKING WATER O	ELECTRICAL UTILITIES HIGH PRESSURE STEAM GENERATION G	STEAM ELECTRIC WASTEWATER DISCHARGE (2)
METALS AND CATIONS (1)													
ALUMINUM	mg/L		<0.2	≤1.5	≤0.100	≤5.0	≤20.0	≤5				≤0.01	
ARSENIC	mg/L	≤0.05	<0.01	<0.05	≤0.05	≤0.10	≤2.0	≤0.05		≤0.05	≤0.005		
BARIUM	mg/L		<0.5	<1.0						≤1.0	≤0.1		
BERYLLIUM	mg/L		<0.1	<1.5	≤0.011	≤0.10	≤0.50						
BORON	mg/L		<5.0	≤5.0		≤0.5	≤1.0	≤5.0		≤5.0	≤0.01		
CADMIUM	mg/L	≤0.01		≤0.005	≤0.0002	≤0.010	≤0.050	≤0.010		≤0.005	≤0.001		
CALCIUM	mg/L							≤1000	≤50	≤200	<75	≤0.01	
COBALT	mg/L					≤0.050	≤5.0	≤1.0					
CHROMIUM	mg/L	≤0.1	<0.05	≤0.100	≤0.04	≤0.1	≤1.0	≤0.05		≤0.05	≤0.0002		≤0.5
HEXAVALENT CHROMIUM	mg/L												≤0.05
COPPER	mg/L		<0.01	<0.05	≤0.005	≤0.20	≤5.0	≤0.5		≤1.0	<1.0	≤0.01	≤0.5
IRON	mg/L		<0.05	<0.3	≤0.300	≤5.0	≤20.0		≤0.3	≤0.3	<0.05	≤0.01	≤1.0
LEAD	mg/L		<0.01	<0.05	≤0.03	≤5.0	≤10.0	≤0.05		≤0.05	≤0.001		
LITHIUM	mg/L					≤2.5	≤2.5						
MAGNESIUM	mg/L								≤25	≤150	<50	≤0.01	
MANGANESE	mg/L		<0.02	≤0.10		≤0.20	≤10.0		≤0.1	≤0.05	<0.01	≤0.01	
MERCURY	µg/L	≤1		≤0.10	≤0.1			≤3		≤1.0	≤0.2		
MOLYBDENUM	mg/L					≤0.010	≤0.010	≤0.01					
NICKEL	mg/L		≤0.002	<0.1	≤0.025	≤0.20	≤2.0						≤0.5
PHOSPHORUS	mg/L									≤0.2			
POTASSIUM	mg/L												
SELENIUM	mg/L		<0.005	<0.01		≤0.020	≤0.020	≤0.01		≤0.01	≤0.002		
SILICA	mg/L								≤50			≤0.01	
SILVER	mg/L		<0.001	<0.005						≤0.05	≤0.005		
SODIUM	mg/L									≤270			
STRONTIUM	mg/L												
THORIUM	µg/L												
TITANIUM	mg/L												
URANIUM	µg/L		<100	<500						≤20	≤1		
VANADIUM	mg/L					≤0.10	≤1.0	≤0.1					
ZINC	mg/L		<0.02	<0.1	≤0.030	≤2.0	≤10.0	≤25		≤5.0	<5.0	≤0.01	≤0.5
ZIRCONIUM	mg/L												

SYMBOLS USED

G-GUIDE LINES
O-OBJECTIVES OR TARGET CONCENTRATIONS
MAC-MAXIMUM ACCEPTABLE CONCENTRATIONS

(1) DERIVED FROM "WATER QUALITY SOURCEBOOK - A GUIDE TO WATER QUALITY PARAMETERS", 1979, ENVIRONMENT CANADA, UNLESS OTHERWISE NOTED.

(2) WASTEWATER EFFLUENT QUALITY RECOMMENDED IN THE DESIGN PHASE ENVIRONMENTAL CODE OF PRACTICE FOR STEAM ELECTRIC POWER GENERATION.

(3) GROSS α AND β VALUES FOR DRINKING WATER DERIVED FROM "GUIDELINES FOR CANADIAN DRINKING WATER QUALITY", 1978, HEALTH AND WELFARE CANADA.

Part I EXTRA No. 27, Vol. 115 ÉDITION SPÉCIALE N° 27, Vol. 115 **Partie I**

OTTAWA, SATURDAY, APRIL 25, 1981 **OTTAWA, SAMEDI 25 AVRIL 1981**

DEPARTMENT OF THE ENVIRONMENT

CLEAN AIR ACT

Thermal Power Generation Emissions—National Guidelines for New Stationary Sources

The Minister of the Environment is pleased to publish the attached Emission Guidelines indicating the quantities and concentrations above which nitrogen oxides, particulate matter and sulphur dioxide should not be emitted from fossil fuel-fired steam-driven electricity generating units, operated in whole or in part for the purpose of the sale of electricity to industry, commerce, or the public. At this time, the guidelines are intended to apply to new units only. The guidelines are part of continuing efforts to diminish the emissions of air-polluting discharges to the atmosphere, and will contribute to that end by restricting such discharges from future additions to electric generating system capacity. The emission limits recommended herein are achievable using control methods now available to the industry for the abatement of the specified air pollutants.

The reduction of similar emissions from existing fossil fuel-fired generating units, and from units to be converted to coal firing from gas or oil fuel, will be the subject of other documents. These will be issued after discussion with the affected provinces as the situation requires, when current joint studies are completed.

To assist provincial agencies and utilities in their assessment of technologies to control the three air pollutants mentioned above, technical documents dealing with the control strategies for nitrogen oxides, particulate matter and sulphur dioxide will be made available. Earlier versions of these documents were distributed to members of a task force composed of representatives of the federal government, provincial governments and technical personnel from industry set up to advise the Department of the Environment on controlling emissions. The control options identified in these technical documents allow for a

MINISTÈRE DE L'ENVIRONNEMENT

LOI SUR LA LUTTE CONTRE LA POLLUTION ATMOSPHÉRIQUE

Lignes directrices nationales sur les dégagements des centrales thermiques nouvelles

Il plaît au ministre de l'Environnement de publier ci-après les lignes directrices nationales qui précisent les quantités et les concentrations dans lesquelles les unités génératrices d'électricité mues à la vapeur, alimentées par des combustibles fossiles et exploitées en tout ou en partie pour vendre l'électricité produite aux établissements industriels et commerciaux ou au public ne devraient pas dégager d'oxydes d'azote, de particules et de dioxyde de soufre. Actuellement, ces lignes directrices ne visent que les nouvelles unités génératrices. Elles s'inscrivent dans la lutte continue contre les dégagements polluants dans l'atmosphère et, à cette fin, contribueront à diminuer les rejets des unités qui viendront s'ajouter au parc actuel. Les limites recommandées peuvent être atteintes à l'aide des méthodes actuellement utilisables dans l'industrie pour réduire les rejets des polluants mentionnés.

D'autres documents viseront les mêmes dégagements des unités existantes et de celles, au gaz ou au pétrole, qui seront converties au charbon. Ils seront publiés après discussion avec les provinces concernées, quand la situation l'exigera et que les études actuellement menées en collaboration seront terminées.

Des documents techniques traitant des stratégies de lutte contre les trois polluants susmentionnés seront mis à la disposition des organismes provinciaux et des services d'utilité publique afin de les aider à évaluer les technologies antipollution. Des versions antérieures de ces documents ont été distribuées aux membres d'un groupe de travail composé de représentants du gouvernement fédéral, des gouvernements provinciaux et des techniciens de l'industrie, mis sur pied pour conseiller le ministère de l'Environnement sur la réduction des dégagements. Les stratégies déterminées dans ces documents permet-choice of methods to control the discharge of air pollutants from this industry.

The emission limits contained in the attached guidelines are based on commercially available technology capable as a minimum of reducing emissions of nitrogen oxides by 50%, particulate matter by 99% and sulphur dioxide by 90%.

The Minister of the Environment recommends that provincial air pollution control agencies adopt these guidelines as minimum standards for new fossil fuel-fired steam generating units within their jurisdiction. However, local conditions, such as density of industrial development, topography and other environmental considerations may necessitate the adoption of more stringent requirements than those suggested in these guidelines.

At this time, no guideline is being issued with respect to emissions from internal combustion engines utilized in the utility industry. An Environment Canada technical document, EPS 3A-AP-76-5, "Air Pollution Emissions and Control Technology: Thermal Power Generation Industry. Vol. 1—Internal Combustion Engines" is however available for consultation.

Interpretation

1. In these guidelines,

"alternative method" means any method of sampling and analysing for an air pollutant which has been demonstrated to the satisfaction of the appropriate regulatory agency to have a consistent and quantitatively known relationship to the reference method under specified conditions;

"averaging period" means a period for determining emission rates based on 720 operating hours which is further defined below;

"construction approval" means authorization granted by the appropriate regulatory agency for the construction of a stationary source of thermal power generation;

"continuous monitoring system" means the complete equipment for sampling, conditioning and analysing emissions or process parameters and for recording data;

"first commercial operation" means the date of the first operation of a steam generating unit at which time electric generating capacity is electrically connected to the transmission and/or distribution systems for the use of tariff-paying customers;

"fossil fuel" means natural gas, petroleum, coal, and any form of gaseous, liquid or solid fuel derived from such for the purpose of creating useful heat;

"new fossil fuel-fired steam generating unit" means a combustion device used for the purpose of burning fossil fuel, at a rate in excess of 250 million BTU/hour heat input (73.3 megajoules per second) for the purpose of producing steam for utility electric generation, and for which first commercial operation commences after May 1, 1981;

"nitrogen oxides" means all oxides of nitrogen except nitrous oxide, as measured by standard reference method EPS 1-AP-77-3;

tront à l'industrie de choisir les méthodes pour réduire ses rejets de polluants atmosphériques.

Les limites de dégagement précisées dans les lignes directrices se fondent sur les techniques disponibles sur le marché, qui sont capables de réduire les émissions d'oxydes d'azote, de particules et de dioxyde de soufre d'au moins 50, 99 et 90% respectivement.

Le ministre de l'Environnement recommande aux organismes provinciaux de lutte contre la pollution atmosphérique d'adopter ces lignes directrices comme normes minimales pour les nouvelles unités génératrices de vapeur au combustible fossile se trouvant sur le territoire relevant de leur compétence. Toutefois, les conditions locales telles que la densité du développement industriel, la topographie et d'autres motifs d'ordre environnemental peuvent nécessiter l'adoption d'exigences plus sévères que les présentes lignes directrices.

Actuellement, aucune ligne directrice ne vise les dégagements des moteurs à combustion interne utilisés par les services d'utilité publique. Toutefois, à cette fin, on peut consulter le document technique publié par Environnement Canada intitulé «La pollution atmosphérique et les techniques de dépollution: production d'énergie par voie thermique. Vol. 1/Moteurs à combustion interne».

Interprétation

1. Dans les présentes,

«approbation de construire» désigne l'autorisation accordée par l'organisme approprié de réglementation pour construire une centrale thermique;

«combustible fossile» désigne le gaz naturel, le pétrole, le charbon et tout dérivé gazeux, liquide ou solide, servant à produire de la chaleur utile;

«date de mise en exploitation» désigne la date de démarrage d'une unité génératrice de vapeur alors que les clients sont branchés à la centrale électrique par le réseau de transmission ou de distribution;

«dispositif de contrôle en continu» désigne l'équipement d'échantillonnage, de traitement et d'analyse des dégagements ou des paramètres d'exploitation et d'enregistrement des données;

«méthode de référence» désigne une méthode d'échantillonnage et d'analyse d'un polluant atmosphérique, recommandée par le ministère de l'Environnement;

«méthode équivalente» désigne une méthode d'échantillonnage et d'analyse d'un polluant atmosphérique, dont on a démontré à l'organisme compétent de réglementation que, dans les conditions précisées, elle donnait une réponse proportionnellement fixe par rapport à celle de la méthode de référence;

«moyenne mobile sur 720 heures» désigne, pour chaque polluant, la moyenne des dégagements moyens horaires consécutifs des 720 heures précédentes de fonctionnement du système. Les intervalles de dégagement nul ne doivent pas servir au calcul de la moyenne mobile;

«nouvelle unité génératrice de vapeur au combustible fossile» désigne un dispositif de combustion servant à brûler du combustible fossile, à un rythme supérieur à 250 millions de B.T.U. par heure d'énergie thermique (73.3 mégajoules par "opacity" means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background;

"reference method" means any method of sampling and analysing for an air pollutant recommended by the Department of the Environment;

"720 hour rolling average" means for each pollutant, the average of the consecutive hourly mean emission rates, determined for the preceding 720 hours of system operation. Intervals of zero emissions are not to be included in the calculation of rolling averages.

Emission Guidelines

2.1 The hourly mean rate of discharge of air contaminants emitted into the ambient air from new fossil fuel-fired utility steam generating units, should not exceed the following, when determined over successive averaging periods as previously defined:

2.1.1 For Nitrogen Oxides expressed as NO_2:

(i) 258 nanograms per joule (258 ng/J), 0.6 pounds per million British thermal units (0.6 lb/10^6 BTU) of heat input, when fired with *solid fossil fuel*,

(ii) 129 ng/J (0.3 lb/10^6 BTU) when fired with *liquid fossil fuel*,

(iii) 86 ng/J (0.2 lb/10^6 BTU) when fired with *gaseous fuel*.

2.1.2 For Particulate Matter: 43 ng/J (0.1 lb/10^6 BTU) of heat input for all fuels.

2.1.3 For Sulphur Dioxide: Generating units emitting more than 258 ng/J (0.6 lb/10^6 BTU) of heat input, when uncontrolled:

(*a*) Those units emitting between 258 ng/J and 2580 ng/J (0.6 lb/10^6 BTU and 6.0 lb/10^6 BTU respectively) should be controlled such that the final emission does not exceed 258 ng/J (0.6 lb/10^6 BTU)

(*b*) Units emitting more than 2580 ng/J (6.0 lb/10^6 BTU) should be controlled so that a minimum of 90% of the uncontrolled emission is captured before release to the atmosphere.

Opacity

3. All new sources should not emit visible emissions with opacity greater than 20 percent, except that the opacity may increase to 40 percent for not more than six (6) minutes in any sixty (60) minute period.

Compliance

4. Natural variations in coal constituents can cause emissions to vary and make enforcement on an hourly or daily impractical. However, calculating the 720 hour rolling average allows the regulatory agency to be informed daily, for each unit, of the maximum average emission rate in the previous 24

seconde) fournie en vue de produire de la vapeur pour produire de l'électricité de service et dont la date de mise en exploitation est ultérieure au 1^{er} mai 1981;

«opacité» désigne l'intensité avec laquelle les dégagements nuisent au passage de la lumière et cachent un objet en arrière-plan;

«oxydes d'azote» désigne tous les oxydes d'azote sauf l'oxyde de diazote, déterminés par la méthode normalisée de référence EPS 1-AP-77-3;

«période de prise de la moyenne» désigne la période sur laquelle on établit le rythme de dégagement sur une période de 720 heures d'exploitation, définie plus haut.

Lignes directrices

2.1 Les dégagements de polluants dans l'air ambiant des nouvelles unités génératrices de vapeur à combustible fossile ne devraient pas dépasser le rythme moyen horaire suivant, déterminé au cours de périodes successives de prise de la moyenne:

2.1.1 en ce qui concerne les oxydes d'azote exprimés en NO_2:

(i) 258 nanogrammes par joule (258 ng/J) ou 0,6 livre par million de B.T.U. (0,6 lb/10^6 B.T.U.) d'énergie thermique fournie, lorsque ces unités sont alimentées en *combustible fossible solide*;

(ii) 129 ng/J (0,3 lb/10^6 B.T.U.) lorsque ces unités sont alimentées en *combustible fossile liquide*;

(iii) 86 ng/J (0,2 lb/10^6 B.T.U.) lorsque ces unités sont alimentées en *combustible gazeux*.

2.1.2 en ce qui concerne les particules: 43 ng/J (0,1 lb/10^6 B.T.U.) d'énergie thermique fournie, quels que soient les combustibles.

2.1.3 en ce qui concerne le dioxyde de soufre, les unités dont les dégagements non épurés dépassent:

a) 258 ng/J (0,6 lb/10^6 B.T.U.) d'énergie thermique fournie, mais sans excéder 2580 ng/J (6,0 lb/10^6 B.T.U.) doivent être dotées de dispositifs d'épuration de façon que le dégagement final ne dépasse pas 258 ng/J (0,6 lb/10^6 B.T.U.)

b) 2580 ng/J (6,0 lb/10^6 B.T.U.) doivent être dotées de dispositifs d'épuration de façon qu'au moins 90% des polluants sont captés avant leur rejet dans l'atmosphère.

Opacité

3. L'opacité des dégagements visibles des sources nouvelles ne devrait pas dépasser 20%; elle peut atteindre 40% pendant pas plus de 6 minutes au cours d'une période de 60 minutes.

Exécution

4. Les variations naturelles de la composition du charbon peuvent faire varier le rythme des dégagements et rendre impraticable la mise en vigueur de limites horaires ou journalières. Toutefois, le calcul d'une moyenne mobile établie sur 720 heures permet à l'organisme de réglementation d'être

hours, since the rolling average must be calculated hourly, on the previous 720 hours' emission values.

It is recognized that the emission guidelines suggested in paragraph 2 and 3 may be exceeded:

(*a*) in the event of malfunction or breakdown in air pollution control equipment; and

(*b*) in the event of startup or shutdown in the operation of the source.

These events should be minimized, both as to frequency of occurrence and duration of each event.

Emission Testing

5.1 Within 180 days from first commercial operation of a fossil fuel-fired steam generating unit and at such other times as the appropriate regulatory agency may require, emission test(s) should be conducted and a written report of results submitted. Emission tests should be conducted by an independent testing agency and witnessed by a representative of the appropriate regulatory agency.

5.2 Emission tests required under paragraph 5.1 should be carried out in the following manner for

(i) nitrogen oxides in accordance with the reference method specified in the Department of the Environment Report EPS 1-AP-77-3 "Standard Reference Methods for Source Testing: Measurement of Emissions of Nitrogen Oxides from Stationary Sources", or an alternative method approved by the appropriate regulatory agency.

(ii) particulate matter in accordance with the reference method specified in the Department of the Environment Report EPS 1-AP-74-1, "Standard Reference Methods for Source Testing: Measurement of Emissions of Particulates from Stationary Sources", or an alternative method approved by the appropriate regulatory agency.

(iii) sulphur dioxide in accordance with the reference method specified in the Department of the Environment Report EPS 1-AP-74-3, Standard Reference Methods for Source Testing: Measurement of Emissions of Sulphur Dioxide from Stationary Sources", or an alternative method approved by the appropriate regulatory agency.

(iv) Visible emissions should be measured in accordance with the reference method specified in the Department of the Environment Report EPS 1-AP-75-2, "Standard Reference Methods for Source Testing: Measurement of Opacity of Emissions from Stationary Sources", or an alternative method approved by the appropriate regulatory agency.

Emission Monitoring

6.1 A continuous monitoring system for measuring the opacity of emissions should be installed on each new source. The installation and operation of the system should be in accordance with the performance specification for transmis-

informé quotidiennement des dégagements moyens maximaux de chaque unité au cours des 24 heures antérieures, étant donné que cette moyenne doit être calculée à chaque heure à partir des quantités dégagées au cours des 720 heures précédentes.

Il est reconnu que les limites de dégagement proposées aux alinéas 2 et 3 peuvent être dépassées:

a) en cas de mauvais fonctionnement ou de panne des dispositifs antipollution; et

b) en cas de démarrage ou d'arrêt du fonctionnement de la source.

La fréquence et la durée de ces événements devraient être réduites au minimum.

Contrôle ponctuel des dégagements

5.1 Moins de 180 jours à compter de la date de mise en exploitation d'une unité génératrice de vapeur au combustible fossile et à tout autre moment exigé par l'organisme compétent de réglementation, des contrôles ponctuels des dégagements devraient être réalisés, et un rapport écrit des résultats présentés. Ces contrôles devraient être réalisés par un organisme indépendant, en présence d'un représentant de l'organisme de réglementation.

5.2 Les contrôles exigés aux termes de l'alinéa 5.1 devraient être réalisés de la manière suivante:

(i) pour ce qui est des oxydes d'azote, conformément à la méthode de référence exposée dans le rapport EPS 1-AP-77-3 intitulé «Méthodes de référence normalisées en vue d'essais aux sources: mesure des émissions d'oxydes d'azote provenant de sources fixes», publié par le ministère de l'Environnement, ou selon une méthode équivalente approuvée par l'organisme compétent de réglementation.

(ii) en ce qui concerne les particules, conformément à la méthode de référence exposée dans le rapport EPS 1-AP-74-1 intitulé «Méthodes de référence normalisées en vue d'essais aux sources: mesure des émissions de particules provenant de sources fixes», publié par le ministère de l'Environnement, ou selon une méthode équivalente approuvée par l'organisme compétent de réglementation.

(iii) en ce qui concerne le dioxyde de soufre, conformément à la méthode de référence exposée dans le rapport EPS 1-AP-74-3, intitulé «Méthodes normalisées de référence pour le contrôle à la source: dosage du dioxyde de soufre émis par les sources fixes», publié par le ministère de l'Environnement, ou selon une méthode équivalente approuvée par l'organisme compétent de réglementation.

(iv) en ce qui concerne les dégagements visibles, conformément à la méthode de référence exposée dans le rapport EPS 1-AP-75-2 intitulé «Méthodes normalisées de référence pour le contrôle de l'opacité des émissions provenant de sources fixes», publié par le ministère de l'Environnement, ou selon une méthode équivalente approuvée par l'organisme compétent de réglementation.

Contrôle continu des dégagements

6.1 Chaque source nouvelle devrait être dotée d'un dispositif de contrôle en continu de l'opacité des dégagements, dont l'installation et le fonctionnement devraient être conformes aux spécifications concernant le fonctionnement des transmissometer systems established by the appropriate regulatory agency.

6.2 A continuous system for measuring sulphur dioxide should be installed on each new source. The installation and operation of the system should be in accordance with the performance specifications for sulphur dioxide monitoring systems established by the appropriate regulatory agency.

6.3 A continuous monitoring system for measuring nitrogen oxides should be installed on each new source. The installation and operation of the system should be in accordance with the performance specifications for nitrogen oxides monitoring systems established by the appropriate regulatory agency.

6.4 All continuous monitoring systems should be installed, calibrated and operating prior to the emission tests required under paragraph 5.1. During the emission tests or within 30 days thereafter, and at such other times as may be required, an evaluation of the performance of the continuous monitoring systems should be conducted by an independent testing agency, in accordance with the requirements and procedures set out in the performance specifications for continuous monitoring systems, established by the appropriate regulatory agency. A written report of the results should be prepared and submitted, within sixty (60) days of the evaluation, to the appropriate regulatory agency.

Notification and Record Keeping

7.1 The emission rates for each pollutant included in this guideline, determined by rolling averages, should be sent to the regulatory authority at least every calendar quarter.

7.2 Operators should keep records of malfunction and breakdowns, and should report each occurrence at least every calendar quarter, to the appropriate regulatory agency.

7.3 The appropriate regulatory authority should be furnished with the following written notifications for sources subject to the provisions of this guideline:

(*a*) notification of the proposed construction of a fossil fuel-fired steam generating unit;

(*b*) notification of the anticipated date of first commercial operation of the source, postmarked not less than 30 days prior to such date; and

(*c*) notification of the date of any performance tests and evaluations of continuous monitoring system performance, postmarked not less than 30 days prior to such date.

siomètres, établies par l'organisme compétent de réglementation.

6.2 Chaque source nouvelle devrait être dotée d'un dispositif de contrôle en continu des dégagements de dioxyde de soufre, dont l'installation et le fonctionnement devraient être conformes aux spécifications établies par l'organisme compétent de réglementation.

6.3 Chaque source nouvelle devrait être dotée d'un dispositif de contrôle en continu des dégagements d'oxydes d'azote, dont l'installation et le fonctionnement devraient être conformes aux spécifications établies par l'organisme compétent de réglementation.

6.4 Les dispositifs de contrôle en continu devraient être installés, étalonnés et ils devraient commencer à fonctionner avant le début des contrôles prescrits à l'alinéa 5.1. Au cours des contrôles ponctuels ou moins de 30 jours après, et à tout moment qu'on pourra l'exiger, ces dispositifs devraient être évalués par un organisme indépendant, conformément aux prescriptions et aux modalités énumérées dans les spécifications établies par l'organisme compétent de réglementation. Un rapport écrit des résultats devrait être rédigé et remis, moins de 60 jours après l'évaluation, à l'organisme compétent de réglementation.

Avertissement et dossiers

7.1 Le rythme de dégagement de chaque polluant visé par les présentes lignes directrices, déterminé par les moyennes mobiles, devrait être communiqué à l'organisme de réglementation au moins à tous les trimestres de l'année civile.

7.2 Les exploitants des installations devraient conserver les dossiers des pannes et mauvais fonctionnements et signaler chaque cas au moins à tous les trimestres de l'année civile à l'organisme compétent de réglementation.

7.3 L'organisme compétent de réglementation devrait être averti par écrit, au sujet des sources visées par les présentes lignes directrices:

a) du projet de construire une unité génératrice de vapeur au combustible fossile;

b) de la date prévue de mise en exploitation de la source, pas moins de 30 jours avant cette date, comme en fera foi le cachet d'oblitération; et

c) de la date de toute évaluation, de fonctionnement et autres, des dispositifs de contrôle en continu, pas moins de 30 jours avant cette date comme en fera foi le cachet d'oblitération.

Registration
SOR/77-734 7 September, 1977

ENVIRONMENTAL CONTAMINANTS ACT

Chlorobiphenyl Regulations No. 1

P.C. 1977-2470 31 August, 1977

Whereas a copy of the proposed Regulation substantially in the form set out in the schedule hereto, was published in the *Canada Gazette* Part I on February 26, 1977;

And Whereas no notice of objection was filed with the Minister pursuant to subsection 5(3) of the Environmental Contaminants Act.

Therefore, His Excellency the Governor General in Council, on the recommendation of the Minister of Fisheries and the Environment and the Minister of National Health and Welfare, pursuant to paragraph 18(*c*) of the Environmental Contaminants Act, is pleased hereby to make the annexed Regulations prescribing certain uses in respect of which certain chlorobiphenyls may not be used.

REGULATIONS PRESCRIBING CERTAIN USES IN RESPECT OF WHICH CERTAIN CHLOROBIPHENYLS MAY NOT BE USED

Short Title

1. These Regulations may be cited as the *Chlorobiphenyl Regulations No. 1*.

Interpretation

2. In these Regulations,

"Act" means the *Environmental Contaminants Act*;

"chlorobiphenyls" means those chlorobiphenyls that have the molecular formula $C_{12}H_{10-n}Cl_n$ in which "n" is greater than 2;

"Minister" means the Minister of the Environment.

Prescription of Uses

3. For the purpose of subsection 8(2) of the Act, the following commercial, manufacturing and processing uses are hereby prescribed effective September 1, 1977, as uses in respect of which chlorobiphenyls may not be used:

(*a*) use in the operation, servicing or maintenance of any product, machinery or equipment other than

(i) electrical capacitors, electrical transformers and associated switchgear and machinery or equipment used to manufacture electrical capacitors, electrical transformers and associated switchgear,

(ii) heat transfer equipment, hydraulic equipment and vapour diffusion pumps that were designed to use

Enregistrement
DORS/77-734 7 septembre 1977

LOI SUR LES CONTAMINANTS DE L'ENVIRONNEMENT

Règlement sur les biphényles chlorés (nº 1)

C.P. 1977-2470 31 août 1977

Vu qu'une copie du Règlement proposé essentiellement dans la forme exposée à l'annexe ci-après a été publiée dans la *Gazette du Canada* (Partie I) le 26 février 1977;

Et vu qu'aucune objection n'a été formulée au ministre en vertu du paragraphe 5(3) de la Loi sur les contaminants de l'environnement.

A ces causes, sur avis conforme du ministre des Pêcheries et de l'Environnement ainsi que du ministre de la Santé nationale et du Bien-être social et en vertu de l'alinéa 18 *c*) de la Loi sur les contaminants de l'environnement, il plaît à Son Excellence le Gouverneur général en conseil de mettre en vigueur le Règlement ci-annexé interdisant certains emplois de certains biphényles chlorés.

RÈGLEMENT INTERDISANT CERTAINS EMPLOIS DE CERTAINS BIPHÉNYLES CHLORÉS

Titre abrégé

1. *Règlement sur les biphényles chlorés (nº 1).*

Définitions

2. On entend par

«biphényles chlorés» les byphényles dont la formule moléculaire est $C_{12}H_{10-n}Cl_n$ où «n» est plus grand que 2,

«loi» la *Loi sur les contaminants de l'environnement*,

«ministre» le ministre de l'Environnement.

Emplois interdits

3. Pour l'application du paragraphe 8(2) de la Loi, les emplois suivants des biphényles chlorés dans le commerce, la fabrication et la transformation sont interdits à compter du 1ᵉʳ septembre 1977:

a) les emplois dans l'exploitation, la réparation et l'entretien de tout produit, machinerie ou équipement sauf:

(i) les condensateurs électriques, les transformateurs électriques et l'appareillage connexe et la machinerie ou l'équipement servant à leur fabrication,

(ii) tout matériel de transfert de la chaleur, tout matériel hydraulique ou toute pompe à diffusion de vapeur utilisés au Canada avant le 1ᵉʳ mars 1977 et dont la conception exige l'emploi de biphényles chlorés et chlorobiphenyls and were in use in Canada before March 1, 1977, and

(iii) machinery or equipment, the operation of which is intended to destroy the chemical structure of chlorobiphenyls; and

(*b*) use as a constituent of any machinery, equipment or product manufactured in or imported into Canada after September 1, 1977 other than electrical capacitors, electrical transformers and associated switchgear.

(iii) la machinerie ou l'équipement destinés à détruire la structure chimique des biphényles chlorés et

b) les emplois dans les produits, la machinerie ou l'équipement fabriqués ou importés au Canada après le 1^{er} septembre 1977, sauf les condensateurs électriques, les transformateurs électriques et l'appareillage connexe.

QUEEN'S PRINTER FOR CANADA, OTTAWA, 1977

IMPRIMEUR DE LA REINE POUR LE CANADA, OTTAWA, 1977

Registration
SOR/80-461 20 June, 1980

ENVIRONMENTAL CONTAMINANTS ACT

Chlorobiphenyl Regulations No. 1, amendment

P.C. 1980-1637 19 June, 1980

Whereas a copy of a proposed amendment to Chlorobiphenyl Regulations No. 1 was published in the *Canada Gazette* Part I on December 2, 1978, pursuant to section 5 of the Environmental Contaminants Act;

Whereas two notices of objection to the proposed amendment were filed with the Minister of the Environment and an Environmental Contaminants Board of Review, established in accordance with section 6 of the Act, conducted an inquiry in accordance with that section;

Whereas on February 25, 1980, the Board submitted its report to the Minister of the Environment and to the Minister of National Health and Welfare together with its recommendations and all evidence that was before the Board in accordance with subsection 6(4) of the Act;

And Whereas the report of the Board was made public by a Press Release dated March 26, 1980 and at a press conference held on March 26, 1980.

Therefore, His Excellency the Governor General in Council, on the recommendation of the Minister of the Environment and the Minister of National Health and Welfare, and in accordance with the recommendations of the Environmental Contaminants Board of Review, pursuant to paragraph 18(*c*) of the Environmental Contaminants Act, is pleased hereby to amend the Chlorobiphenyl Regulations No. 1, C.R.C., c. 564, in accordance with the schedule hereto.

SCHEDULE

1. Section 2 of the *Chlorobiphenyl Regulations No. 1* is revoked and the following substituted therefor:

"2. In these Regulations,

"Act" means the *Environmental Contaminants Act*;

"chlorobiphenyls" means those chlorobiphenyls that have the molecular formula $C_{12}H_{10-n}Cl_n$ in which "n" is greater than 2;

"electrical transformers" includes transformer/rectifier assemblies installed in a common enclosure;

"Minister" means the Minister of the Environment."

Enregistrement
DORS/80-461 20 juin 1980

LOI SUR LES CONTAMINANTS DE L'ENVIRONNEMENT

Règlement n° 1 sur les biphényles chlorés—Modification

C.P. 1980-1637 19 juin 1980

Vu qu'une copie d'un projet de modification au Règlement n° 1 sur les biphényles chlorés a été publiée dans la *Gazette du Canada*, Partie I, le 2 décembre 1978, en vertu de l'article 5 de la Loi sur les contaminants de l'environnement;

Vu que deux avis d'opposition à ce projet de modification ont été déposés auprès du ministre de l'Environnement et qu'une Commission d'étude sur les contaminants de l'environnement établie en vertu de l'article 6 de la Loi a fait enquête aux termes de cet article;

Vu que le 25 février 1980, la Commission a présenté son rapport au ministre de l'Environnement et au ministre de la Santé nationale et du Bien-être social, ainsi que ses recommendations et l'ensemble de la preuve dont elle a pris connaissance, conformément au paragraphe 6(4) de la Loi;

Et vu que ledit rapport a été rendu public le 26 mars 1980 par communiqué et conférence de presse.

À ces causes, sur avis conforme du ministre de l'Environnement et du ministre de la Santé nationale et du Bien-être social, suivant les recommandations de la Commission et en vertu de l'alinéa 18*c*) de la Loi sur les contaminants de l'environnement, il plaît à Son Excellence le Gouverneur général en conseil de modifier, conformément à l'annexe ci-après, le Règlement n° 1 sur les biphényles chlorés, C.R.C., c. 564.

ANNEXE

1. L'article 2 du *Règlement n° 1 sur les biphényles chlorés* est abrogé et remplacé par ce qui suit:

«2. Dans le présent règlement,

«biphényles chlorés» désigne les composés de la formule moléculaire $C_{12}H_{10-n}Cl_n$ où «n» est plus grand que 2;

«Loi» désigne la *Loi sur les contaminants de l'environnement*;

«Ministre» désigne le ministre de l'Environnement;

«transformateurs électriques» comprend les ensembles transformateurs/redresseurs installés dans une même enceinte.»

2. Section 3 of the said Regulations is revoked and the following substituted therefor:

"3. For the purpose of subsection 8(2) of the Act, the following commercial, manufacturing or processing uses are hereby prescribed as uses in respect of which chlorobiphenyls may not be used:

(*a*) use in the operation of any product, machinery or equipment other than

(i) electrical capacitors, electrical transformers and associated electrical equipment,

(ii) heat transfer equipment, hydraulic equipment, electromagnets, and vapour diffusion pumps that were designed to use chlorobiphenyls and were in use in Canada before September 1, 1977, and

(iii) machinery or equipment, the operation of which is intended to destroy the chemical structure of chlorobiphenyls;

(*b*) use in the operation of electromagnets that are used to handle food, animal feed or anything intended to be added to food or animal feed for any purpose whatsoever;

(*c*) use as a constituent of any product, machinery or equipment manufactured in or imported into Canada after September 1, 1977, other than electrical capacitors, electrical transformers and associated electrical equipment;

(*d*) use as a constituent of electrical capacitors, electrical transformers and associated electrical equipment manufactured in or imported into Canada after July 1, 1980;

(*e*) use in the servicing or maintenance of any product, machinery or equipment, other than electromagnets, electrical transformers and associated electrical equipment; and

(*f*) use as new filling or as make-up fluid in the servicing or maintenance of any electromagnet, electrical transformer or associated electrical equipment."

3. Sections 1 and 2 shall come into force on July 1, 1980.

2. L'article 3 dudit règlement est abrogé et remplacé par ce qui suit:

«3. Aux fins du paragraphe 8(2) de la Loi, les emplois suivants des biphényles chlorés dans le commerce, la fabrication ou la transformation sont interdits:

a) l'emploi dans l'exploitation de tout produit, machinerie ou équipement, sauf

(i) les condensateurs électriques, les transformateurs électriques et l'équipement électrique connexe,

(ii) l'équipement de transfert de la chaleur, l'équipement hydraulique, les électro-aimants et les pompes à diffusion de vapeur conçus pour utiliser des biphényles chlorés et mis en service au Canada avant le 1er septembre 1977, et

(iii) la machinerie ou l'équipement destinés à détruire la structure chimique des biphényles chlorés;

b) l'emploi dans l'exploitation d'électro-aimants utilisés pour la manutention d'aliments destinés à l'homme ou aux animaux ou de leurs additifs;

c) l'emploi dans les produits, la machinerie ou l'équipement fabriqués ou importés au Canada après le 1er septembre 1977, sauf les condensateurs électriques, les transformateurs électriques et l'équipement électrique connexe;

d) l'emploi dans les condensateurs électriques, les transformateurs électriques et l'équipement électrique connexe fabriqués ou importés au Canada après le 1er juillet 1980;

e) l'emploi pour la réparation ou l'entretien des produits, de la machinerie ou de l'équipement autres que les électro-aimants, les transformateurs électriques et l'équipement électrique connexe; et

f) l'emploi comme nouveau fluide de remplissage ou comme fluide d'appoint pour la réparation ou l'entretien des électro-aimants, des transformateurs électriques ou de l'équipement électrique connexe.»

3. Les articles 1 et 2 entrent en vigueur le 1er juillet 1980.

EXPLANATORY NOTE

(This note is not part of the Regulation, but is intended only for information purposes.)

These amendments now have the following effects:

(1) The use of chlorobiphenyls is restricted to use in those items listed in subparagraphs 3(*a*)(i), (ii) and (iii).

(2) Paragraph 3(*b*) prohibits the use of chlorobiphenyls in the operation of electromagnets that are used to handle food, animal feed or anything intended to be added to food or animal feed for any purpose whatsoever.

(3) Paragraph 3(*c*) prohibits the use of chlorobiphenyls as a constituent of any product manufactured in or imported into Canada after September 1, 1977, other than electrical capacitors, electrical transformers and associated electrical equipment.

(4) Subsection 3(*d*) removes, effective July 1, 1980, the exemption regarding electrical capacitors, electrical transformers and associated electrical equipment so that thereafter the use of chlorobiphenyls is totally prohibited as a constituent of any product, machinery or equipment manufactured in or imported into Canada.

(5) Paragraph 3(*e*) allows the use of chlorobiphenyls after July 1, 1980 in the servicing or maintenance of electromagnets, electrical transformers and associated electrical equipment. This means, for example, that existing chlorobiphenyls may be removed, filtered and returned to the same piece of equipment. However, in paragraph 3(*f*) the use of additional chlorobiphenyls as a new filling or as make-up in servicing or maintenance is prohibited. This does not, though, prohibit the use of a suitable non-chlorobiphenyl fluid as a new filling or as make-up.

NOTE EXPLICATIVE

(La présente note ne fait pas partie du règlement et n'est publiée qu'à titre d'information.)

Ces modifications qui entrent en vigueur le 1ᵉʳ juillet 1980 visent:

(1) à limiter l'emploi de biphényles chlorés dans l'exploitation de tout produit, machinerie ou équipement sauf certains articles;

(2) à interdire leur emploi dans les électro-aimants utilisés pour la manutention dans l'industrie alimentaire;

(3) à interdire leur emploi dans les produits fabriqués ou importés au Canada après le 1ᵉʳ septembre 1977, sauf les condensateurs électriques, les transformateurs électriques et l'équipement électrique connexe;

(4) à ne plus exempter les articles visés au paragraphe (3) de la présente note;

(5) à interdire leur emploi pour la réparation ou l'entretien des produits de la machinerie ou de l'équipement sauf certains articles;

(6) à interdire leur emploi comme nouveau fluide de remplissage ou comme fluide d'appoint pour la réparation ou l'entretien de certains articles.

QUEEN'S PRINTER FOR CANADA, OTTAWA, 1980 IMPRIMEUR DE LA REINE POUR LE CANADA, OTTAWA, 1980

Registration
SOR/85-406 2 May, 1985

ENVIRONMENTAL CONTAMINANTS ACT

Chlorobiphenyl Regulations No. 2 (Product)

P.C. 1985-1473 2 May, 1985

Whereas a copy of the proposed regulations substantially in the form set out in the schedule hereto was published in the *Canada Gazette* Part I on January 21, 1984;

And Whereas the two notices of objection to the proposed regulations that were filed with the Minister pursuant to subsection 5(3) of the Environmental Contaminants Act were subsequently withdrawn.

Therefore, Her Excellency the Governor General in Council, on the recommendation of the Minister of the Environment and the Minister of National Health and Welfare, pursuant to paragraph 18(*e*) of the Environmental Contaminants Act*, is pleased hereby to make the annexed Regulations prescribing the maximum concentration of chlorobiphenyls that may be contained in certain products, effective August 1, 1985.

REGULATIONS PRESCRIBING THE MAXIMUM CONCENTRATION OF CHLOROBIPHENYLS THAT MAY BE CONTAINED IN CERTAIN PRODUCTS

Short Title

1. This Regulation may be cited as the *Chlorobiphenyl Regulations No. 2 (Product)*.

Interpretation

2. In these Regulations,

"Act" means the *Environmental Contaminants Act*;

"electrical transformer" includes a rectifier-transformer assembly installed in a common enclosure.

Prescription

3. (1) For the purpose of subsection 8(4) of the Act, the maximum concentration prescribed in respect of chlorobiphenyls contained in a product that is

(*a*) an electrical capacitor,

(*b*) an electrical transformer and its associated electrical equipment,

(*c*) an electro-magnet,

(*d*) heat transfer equipment,

(*e*) hydraulic equipment, or

(*f*) a vapour diffusion pump

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* S.C. 1974-75-76, c. 72

Enregistrement
DORS/85-406 2 mai 1985

LOI SUR LES CONTAMINANTS DE L'ENVIRONNEMENT

Règlement nº 2 sur les biphényles chlorés (produits)

C.P. 1985-1473 2 mai 1985

Vu qu'une copie du projet de règlement essentiellement dans la forme exposée à l'annexe ci-après a été publiée dans la *Gazette du Canada*, Partie I, le 21 janvier 1984;

Et vu que les deux avis d'opposition au projet de règlement qui ont été déposés auprès du ministre de l'Environnement conformément au paragraphe 5(3) de la Loi sur les contaminants de l'environnement ont été retirés.

À ces causes, sur avis conforme du ministre de l'Environnement et du ministre de la Santé nationale et du Bien-être social et en vertu de l'alinéa 18*e*) de la Loi sur les contaminants de l'environnement*, il plaît à Son Excellence le Gouverneur général en conseil de prendre, à compter du 1er août 1985, le Règlement prescrivant la concentration maximale de biphényles chlorés dans certains produits, ci-après.

RÈGLEMENT PRESCRIVANT LA CONCENTRATION MAXIMALE DE BIPHÉNYLES CHLORÉS DANS CERTAINS PRODUITS

Titre abrégé

1. Le présent règlement peut être cité sous le titre: *Règlement nº 2 sur les biphényles chlorés (produits)*.

Définitions

2. Dans le présent règlement,

«Loi» désigne la *Loi sur les contaminants de l'environnement*;

«transformateur électrique» comprend un ensemble transformateur-redresseur installé dans une même enceinte.

Concentration prescrite

3. (1) Aux fins du paragraphe 8(4) de la Loi, la concentration maximale prescrite de biphényles chlorés dans

a) un condensateur électrique,

b) un transformateur électrique et l'équipement électrique connexe,

c) un électro-aimant,

d) l'équipement de transport de la chaleur,

e) l'équipement hydraulique, ou

f) une pompe à diffusion de vapeur,

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* S.C. 1974-75-76, c. 72

designed to use chlorobiphenyls, is 50 parts per million by weight of the liquid therein.

(2) Subsection (1) does not apply to the concentration of chlorobiphenyls in a product referred to in paragraphs (1)(*a*) to (*f*) that is

(*a*) offered for sale as a necessary and integral part of an immovable building, plant or structure that is offered for sale;

(*b*) imported for destruction of the chemical structure of the chlorobiphenyls contained therein; or

(*c*) offered for sale for destruction or storage awaiting destruction of the chemical structure of the chlorobiphenyls contained therein.

EXPLANATORY NOTE

(This note is not part of the Regulation, but is intended only for information purposes.)

These Regulations prescribe the maximum concentration of chlorobiphenyls that may be contained in the listed products at the time they are imported, manufactured or knowingly offered for sale.

conçus pour utiliser des biphényles chlorés, est de 50 parties par million, en poids, du liquide s'y trouvant.

(2) Le paragraphe (1) ne s'applique pas aux produits visés aux alinéas (1)*a*) à *f*) qui sont

a) mis en vente en tant que partie essentielle ou intégrante d'un immeuble, d'une installation ou d'une structure non déplaçables mis en vente;

b) importés pour fins de destruction de la structure chimique des biphényles chlorés qui y sont contenus; ou

c) mis en vente pour fins de destruction ou d'entreposage en attente de la destruction de la structure chimique des biphényles chlorés qui y sont contenus.

NOTE EXPLICATIVE

(La présente note ne fait pas partie du règlement et n'est publiée qu'à titre d'information.)

Le règlement prescrit la concentration maximale de biphényles chlorés qui est permise dans certains produits au moment où ils sont importés, fabriqués ou sciemment mis en vente.

QUEEN'S PRINTER FOR CANADA, OTTAWA, 1985

IMPRIMEUR DE LA REINE POUR LE CANADA, OTTAWA, 1985

Registration
SOR/85-407 2 May, 1985

ENVIRONMENTAL CONTAMINANTS ACT

Chlorobiphenyl Regulations No. 3 (Release)

P.C. 1985-1472 2 May, 1985

Whereas a copy of the proposed regulations substantially in the form set out in the schedule hereto was published in the *Canada Gazette* Part I on January 21, 1984;

And Whereas the two notices of objection to the proposed regulations that were filed with the Minister pursuant to subsection 5(3) of the Environmental Contaminants Act were subsequently withdrawn.

Therefore, Her Excellency the Governor General in Council, on the recommendation of the Minister of the Environment and the Minister of National Health and Welfare, pursuant to paragraph 18(*a*) of the Environmental Contaminants Act*, is pleased hereby to make the annexed Regulations prescribing the maximum concentration and quantity of chlorobiphenyls that may be released into the environment, effective August 1, 1985.

REGULATIONS PRESCRIBING THE MAXIMUM CONCENTRATION AND QUANTITY OF CHLOROBIPHENYLS THAT MAY BE RELEASED INTO THE ENVIRONMENT

Short Title

1. These Regulations may be cited as the *Chlorobiphenyl Regulations No. 3 (Release)*.

Interpretation

2. In these Regulations,

"Act" means the *Environmental Contaminants Act*;

"electrical transformers" includes rectifier-transformer assemblies installed in a common enclosure;

"package" means any receptacle or enveloping material that contains any of the equipment referred to in section 4.

Maximum Concentration

3. For the purposes of subsection 8(1) of the Act, the maximum concentration of chlorobiphenyls that may be released into the environment in any geographical area of Canada, other than any water or place to which subsection 33(2) of the *Fisheries Act* applies, in the course of

(*a*) a commercial, manufacturing or processing activity, other than

(i) an application to a road surface, or

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* S.C. 1974-75-76, c. 72

Enregistrement
DORS/85-407 2 mai 1985

LOI SUR LES CONTAMINANTS DE L'ENVIRONNEMENT

Règlement nº 3 sur les biphényles chlorés (rejets)

C.P. 1985-1472 2 mai 1985

Vu qu'une copie du règlement proposé essentiellement dans la forme exposée à l'annexe ci-après a été publiée dans la *Gazette du Canada*, Partie I, le 21 janvier 1984;

Et vu que les deux avis d'opposition au projet de règlement qui ont été déposés auprès du ministre de l'Environnement conformément au paragraphe 5(3) de la Loi sur les contaminants de l'environnement ont été retirés.

À ces causes, sur avis conforme du ministre de l'Environnement et du ministre de la Santé nationale et du Bien-être social et en vertu de l'alinéa 18*a*) de la Loi sur les contaminants de l'environnement il plaît à Son Excellence le Gouverneur général en conseil de prendre, à compter du 1er août 1985, le Règlement fixant la concentration et la quantité maximales de biphényles chlorés qui peuvent être rejetés dans l'environnement, ci-après.

RÈGLEMENT FIXANT LA CONCENTRATION ET LA QUANTITÉ MAXIMALES DE BIPHÉNYLES CHLORÉS QUI PEUVENT ÊTRE REJETÉS DANS L'ENVIRONNEMENT

Titre abrégé

1. Le présent règlement peut être cité sous le titre: *Règlement nº 3 sur les biphényles chlorés (rejets)*.

Définitions

[illegible] le présent règlement,

«emballage» désigne un contenant ou un matériau servant à envelopper les pièces d'équipement visées à l'article 4;

«Loi» désigne la *Loi sur les contaminants de l'environnement*;

«transformateur électrique» comprend un ensemble transformateur-redresseur installé dans une même enceinte.

Concentration prescrite

3. Aux fins du paragraphe 8(1) de la Loi, la concentration maximale de biphényles chlorés que toute personne peut rejeter ou permettre de rejeter dans l'environnement dans une région du Canada, sauf les eaux ou les lieux visés au paragraphe 33(2) de la *Loi sur les pêcheries*,

a) dans le cadre d'une opération commerciale, de fabrication ou de traitement, autre

(i) qu'un traitement de surface d'une route, ou

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* S.C. 1974-75-76, c. 72

(ii) an activity described in section 4

is 50 parts per million by weight; and

(*b*) an application to a road surface, is five parts per million by weight.

Maximum Quantity

4. For the purposes of subsection 8(1) of the Act, the maximum quantity of chlorobiphenyls that may be released into the environment in any geographical area of Canada, other than any water or place to which subsection 33(2) of the *Fisheries Act* applies, in the course of the operation, servicing, maintenance, decommissioning, transportation or storage of

(*a*) electrical transformers and associated electrical equipment manufactured in or imported into Canada before July 1, 1980,

(*b*) electro-magnets designed to use chlorobiphenyls and manufactured in or imported into Canada before September 1, 1977,

(*c*) electrical capacitors manufactured in or imported into Canada before July , 1980, or

(*d*) heat transfer equipment, hydraulic equipment or vapour diffusion pumps designed to use chlorobiphenyls and in use in Canada before September 1, 1977,

is 1 g per day

(*e*) for any one piece of equipment, or

(*f*) for any one package of equipment.

EXPLANATORY NOTE

(This note is not part of the Regulation, but is intended only for information purposes.)

These Regulations prescribe the maximum concentration and quantity of chlorobiphenyls that may be released into the environment in the prescribed geographical area of Canada in the course of commercial, manufacturing and processing activities.

(ii) qu'une opération visée à l'article 4,

est de 50 parties par million, en poids, et

b) au cours d'un traitement de surface d'une route, est de cinq parties par million en poids.

Quantité maximale

4. Aux fins du paragraphe 8(1) de la Loi, la quantité maximale de biphényles chlorés qui peut être rejetée dans l'environnement dans une région du Canada, sauf les eaux ou les lieux visés au paragraphe 33(2) de la *Loi sur les pêcheries*, au cours de l'exploitation, de l'entretien, de la réparation, de la mise hors service, du transport ou de l'entreposage

a) d'un transformateur électrique et de l'équipement électrique connexe, fabriqués ou importés au Canada avant le 1er juillet 1980,

b) d'un électro-aimant conçu pour utiliser des biphényles chlorés et fabriqué ou importé au Canada avant le 1er septembre 1977,

c) d'un condensateur électrique fabriqué ou importé au Canada avant le 1er juillet 1980, ou

d) de l'équipement de transfert de la chaleur, de l'équipement hydraulique ou d'une pompe à diffusion de vapeur conçus pour utiliser des biphényles chlorés et utilisés au Canada avant le 1er septembre 1977,

est de 1 g par jour

e) pour chaque pièce d'équipement, ou

f) pour chaque emballage d'équipement.

NOTE EXPLICATIVE

(La présente note ne fait pas partie du règlement et n'est publiée qu'à titre d'information.)

Le règlement prescrit la quantité et la concentration maximales de biphényles chlorés que toute personne peut délibérément rejeter ou permettre de rejeter dans l'environnement à certains endroits au Canada, au cours d'opérations commerciales, de fabrication et de traitement.

QUEEN'S PRINTER FOR CANADA, OTTAWA, 1985

IMPRIMEUR DE LA REINE POUR LE CANADA, OTTAWA, 1985

APPENDIX D

RATIONALE FOR RECOMMENDATIONS ON ONCE-THROUGH COOLING SYSTEMS

APPENDIX D

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D. RATIONALE FOR RECOMMENDATIONS ON ONCE-THROUGH COOLING WATER

D.1 Description of Once-Through Cooling Systems

For the purposes of the Design Phase Code of Practice, once-through cooling (Type 1) water streams at steam electric generating stations include both once-through condenser cooling water and auxiliary cooling water that is not considered potentially contaminated.

Figure D.1 illustrates the major components of a typical once-through or open-cycle condenser cooling system. The system can be divided into distinct sections: the intake, forebay, screens, pumps, condenser and outfall. Water is withdrawn from the source water body through the intake into the forebay where large debris is removed by trash racks to prevent damage to the pumps and condenser tubes. Vertical travelling screens are traditionally used to prevent small debris and fish from entering the system. After the travelling screens, large cooling water pumps circulate the water through the condenser, which typically contains several thousand tubes about 2.5 cm in diameter. Heat rejected in the condensation of exhaust steam from the turbines is transferred to the cooling water passing through the condenser tubes. From the condenser, the heated cooling water is discharged to the receiving water body via an outfall channel or conduit.

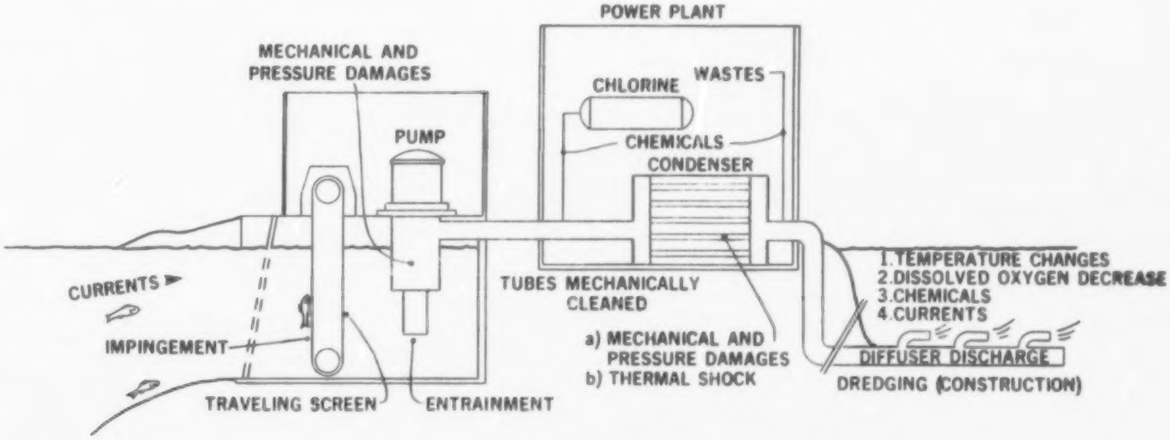

POWER PLANT
MECHANICAL AND PRESSURE DAMAGES
CHLORINE
WASTES
PUMP
CHEMICALS
CONDENSER
CURRENTS
TUBES MECHANICALLY CLEANED
1.TEMPERATURE CHANGES
2.DISSOLVED OXYGEN DECREASE
3.CHEMICALS
4.CURRENTS
IMPINGEMENT
a) MECHANICAL AND PRESSURE DAMAGES
b) THERMAL SHOCK
DIFFUSER DISCHARGE
DREDGING (CONSTRUCTION)
TRAVELING SCREEN
ENTRAINMENT

FIGURE D.1 SCHEMATIC REPRESENTATION OF A TYPICAL ONCE-THROUGH CONDENSER COOLING SYSTEM

Typical auxiliary cooling systems for a fossil-fuelled and a CANDU nuclear station are shown schematically in Figure D.2. At fossil-fuelled stations, auxiliary cooling water is used to cool conventional equipment such as hoppers, bearings and pumps. CANDU nuclear stations use substantial quantities of auxiliary cooling water to cool reactor equipment, most of which is used for moderater water cooling, in addition to conventional equipment cooling requirements. Auxiliary cooling water is usually drawn from the forebay or from some point on the condenser cooling water intake prior to the condenser. It is passed through additional low or high pressure pumps and often distributed through a fairly extensive piping system to the various equipment to be cooled. Plate heat exchangers are typically used for cooling oil or other fluid which in turn cools the equipment. In some cases, a secondary water cooling loop with double heat exchangers is used which prevents the primary once-through auxiliary cooling water stream from becoming contaminated in the event of a single heat exchanger leak or rupture. A positive pressure differential from the cooling water in the primary circuit to cooling fluid in the secondary circuit will also minimize the potential for contamination. Absence of a secondary loop or positive pressure differential is the criterion herein used for designation of the primary auxiliary cooling water flow stream as potentially contaminated (Type 2).

D.2 Nature of Environmental Concerns

Although effects in receiving water due to heated discharges from once-through cooling systems remain of concern, there has been a recent shift in emphasis to the hazards presented by the phenomena of entrapment, impingement, and entrainment. Entrapment refers to the trapping of organisms in the intake, forebay, or screenwell, impingement the forcing and maintenance of organisms upon the intake screens, and entrainment the inclusion of aquatic organisms in the cooling water flow stream through the condensers and heat exchangers.

To properly assess the effects on aquatic populations of once-through condenser cooling systems, it is useful to examine the hazards presented at different points along the flow path. Fish and other aquatic organisms are initially entrapped into the station cooling water flow stream by failure or inability to avoid being drawn into the cooling water intake. Free-floating fish eggs, larvae, and planktonic organisms are highly vulnerable to being entrained or passively drawn into the cooling system. In the case of a submerged intake, sudden pressure changes can be experienced by the entrapped organisms as they are conveyed from a depth upwards into the forebay. Once fish become trapped in the forebay they have little or no opportunity to return to the source water

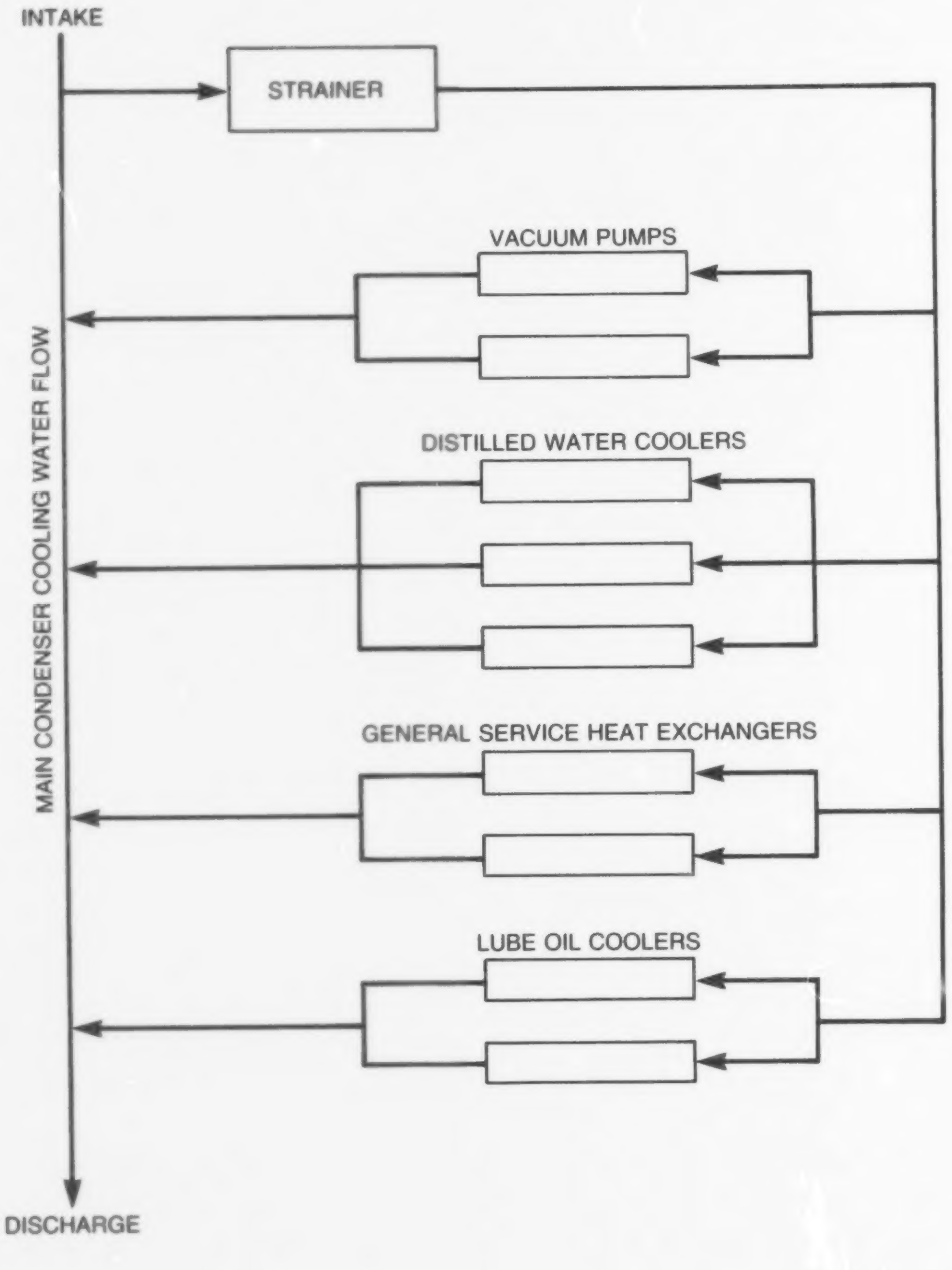

INTAKE
STRAINER
VACUUM PUMPS
DISTILLED WATER COOLERS
GENERAL SERVICE HEAT EXCHANGERS
LUBE OIL COOLERS
MAIN CONDENSER COOLING WATER FLOW
DISCHARGE

FIGURE D.2 SCHEMATIC REPRESENTATION OF A TYPICAL AUXILIARY COOLING WATER SYSTEM (1)

body. Eventually most fish trapped in the forebay can be expected to be impinged on the intake screens, after becoming exhausted from swimming against the current. They may suffer physical abrasion in passing through the trash racks and, once impinged, mortality can occur because of descaling during escape attempts and from the force of the screen wash sprays, and by asphyxiation due to closure of the opercula or removal from the water for prolonged periods (2).

Ichthyoplankton (fish eggs and larvae) and other organisms small enough to pass through the travelling screens (typically 1 cm opening) will be subjected to physical stress in the pumps, water box and condenser, and to exposure to chemicals added to control biofouling in the condenser tubes and to rapid temperature rise in passage through the condenser tubes.

It is reasonable to assume that all organisms that are entrained in the auxiliary cooling water flow stream will be killed because of the extensive water distribution network and, in the case of moderator water cooling at CANDU nuclear stations, because of lethal temperatures (a 44°C temperature rise through the heat exchanger is typical).

On discharge of the cooling water, organisms in it may be subjected to further mechanical damage in the discharge facility and to further thermal shock as they return to ambient temperatures in the water body. Organisms in the receiving water which have not passed through the plant may be entrained into the thermal plume (plume entrainment) and subjected to thermal shock.

The primary consideration in protecting entrained organisms is minimization of mortality and sublethal effects to entrained ichthyoplankton (fish eggs and larvae) and invertebrate larvae. The loss of large numbers of ichthyoplankton, with typical regeneration times of two to four years, represents a larger impact on the ultimate population of adults than do losses of phytoplankton and zooplankton, which have regeneration times of a few hours and a few days respectively (3). If most entrained organisms are destroyed in passage through the cooling system, then the need to prohibit once-through cooling must be carefully considered from the point of view of population loss.

The number of organisms susceptible to impingement and entrainment are proportional to the volume of intake water and the concentrations of organisms in that water. Plant and intake siting considerations, through avoidance of waters with high aquatic species populations, can be effective in reducing the concentrations in intake water. Further reduction in the number of organisms exposed to potentially lethal conditions in the cooling system can be achieved through minimizing the intake volume.

However, temperature rise of cooling water through the condenser is inversely proportional to volume. Hence, there is a trade-off between reducing the volume and raising the temperature of exposure.

It is recognized that the technology currently exists, in the form of recirculating or closed-cycle cooling, to essentially eliminate the major concerns associated with once-through cooling. Recirculating cooling systems, however, have a number of disadvantages including increased land requirements, need for biofouling chemicals, potential for fogging, increased water loss (with some systems) and increased cost. Based on these considerations, a total prohibition of once-through cooling has not been proposed for all new stations or station expansions. However, any new once-through cooling systems that are employed should be operated within limitations that will prevent significant detrimental effects on the aquatic environment.

D.3 Categorization of Water Bodies

D.3.1 General

The environmental concerns associated with once-through cooling vary depending on the size and characteristics of the water body from which the cooling water is withdrawn or to which it is discharged. Five basic water body categories may be considered for the purpose of describing more specifically the nature of these concerns. These are:

(i) large freshwater lakes and reservoirs,
(ii) small freshwater lakes and reservoirs,
(iii) rivers,
(iv) estuaries, and
(v) marine waters.

The environmental concerns associated with using these water systems as sources of or receptors for once-through cooling water are discussed in the following sections.

D.3.2 Large Freshwater Lakes and Reservoirs

For the purpose of this environmental code, large freshwater lakes and reservoirs are defined as any lake or reservoir from which only a small percentage of the total water volume is withdrawn annually for power plant cooling.

In such water bodies, special attention must be given to the nearshore or littoral zones as these areas are usually vital to the biological well-being of the system.

Most fish spend some portion of their life cycle in the shallower, nearshore areas where suitable conditions exist for spawning, nursery, rearing and migration.

It is important to recognize the size of this vital nearshore zone in a large lake relative to the overall size of the lake. Figure D.3 shows the approximate nearshore area less than 10 m deep in Lake Ontario. The protection of this very narrow band of high biological productivity is vital to the biological well being of the entire lake.

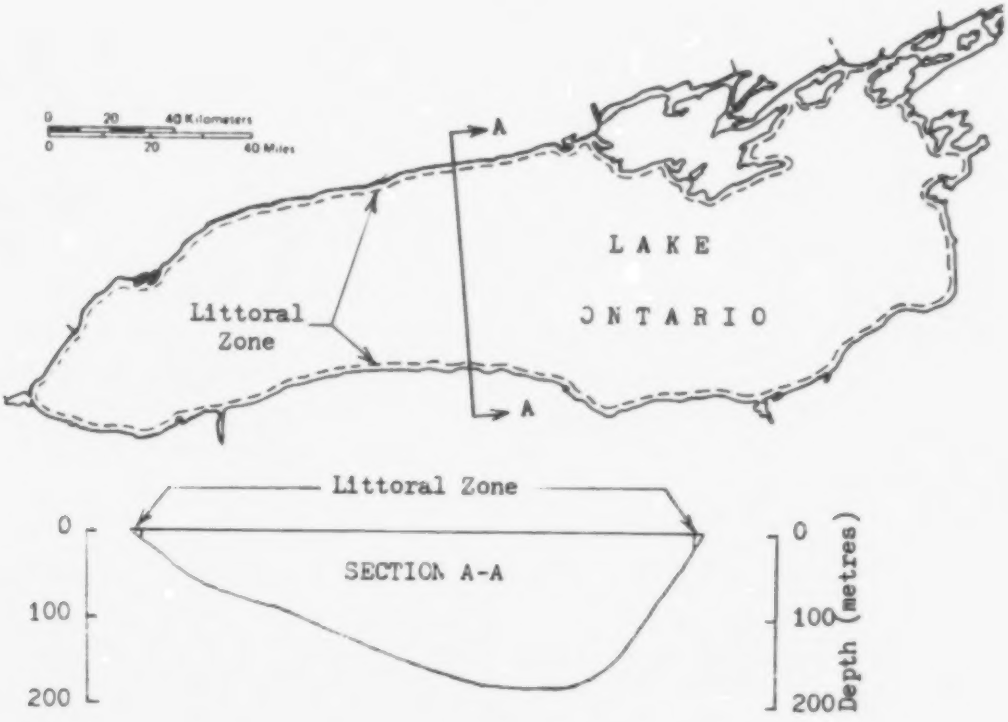

0 20 40 Kilometers
0 20 40 Miles
A
A
LAKE
ONTARIO
Littoral Zone
Littoral Zone
SECTION A-A
0
100
200
0
100
200
Depth (metres)

FIGURE D.3 LAKE ONTARIO NEARSHORE ZONE (LESS THAN 10 METRES DEEP).

Ichthyoplankton concentrations in the nearshore or littoral zone are generally much higher than in open water. Figure D.4 shows typical distributions of larvae from a lake shoreline towards deeper water. This figure illustrates that a high percentage of the larval population of some species resides in the nearshore zone.

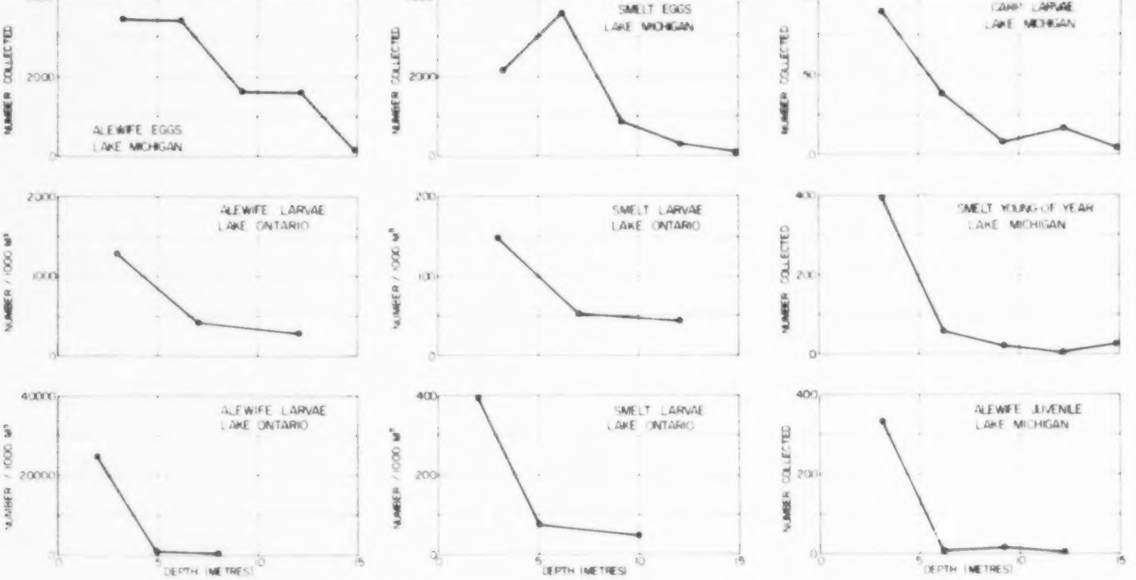


FIGURE D.4 ICHTHYOPLANKTON (FISH EGGS AND LARVAE) DISTRIBUTIONS IN NEARSHORE ZONES OF LARGE LAKES (4, 5, 6)

Further, the eggs and larvae can be conveyed along shorelines by lake currents from spawning or rearing areas to areas where they are susceptible to entrainment in power plant intakes.

Large power plants withdrawing water from the nearshore zone of a lake can pass a large portion of the water within that zone through their cooling systems. Because of the high concentrations of fish larvae in the nearshore zone, this can result in the entrainment of a large percentage of the lake's larval populations, leading to concern over serious and possible irreversible decline of certain species in the system.

A better appreciation of the magnitude of this concern can be gained by some examples. It has been estimated, for example, that daily entrainment of larval and juvenile fishes at the 4000-MW Nanticoke station with full capacity operation would be about 31 000 during May-June and 539 000 during July-August based on concentrations present in Lake Erie in 1974 (7). This totals about 35 000 000 larval and juvenile fish during the four month period.

A study (6) at the 2000-MW Pickering nuclear station on Lake Ontario estimated fish egg and larval entrainment with full capacity operation in the period May to September, 1977 to be 188 000 000 and 608 000 000 respectively. The larval estimates included only rainbow smelt and alewife, but these represent more than 99 percent of the larvae present in the nearshore waters. When considering these estimates it should be recognized that the Pickering G.S. will increase in capacity to 4320 MW and that anywhere from 3400 to 6800 MW of additional capacity is planned for the Darlington nuclear station a short distance up current on the same shoreline.

The numbers of yellow perch larvae entrained in 1975 at the 3100 MW Munroe power plant on Lake Erie were estimated to be between 2 180 000 and 11 410 000 (8). An assumption of 70 percent entrainment mortality was estimated to translate into an annual loss in fisheries yield of 110 000 to 406 000 pounds, or 2 to 8 percent of the annual yellow perch harvest in the western basin of Lake Erie. The study concluded that:

> "With additional plants with once-through cooling being situated in the western basin, it is easily seen that their combined pressure on the fisheries will be substantial, and when this is coupled with excessive harvests, it could tip the yellow perch fisheries into an irreversible decline."

The number of fish eggs and larvae estimated to be entrained per year at the Bruce A nuclear station on Lake Huron is 15 700 000 (three species) and 39 700 000 respectively, with two of the station's four units operating (9). This station is also located a short distance distance along the shoreline from the similarly sized Bruce B station, the 200-MW Douglas Point nuclear station and the water intakes for the Bruce heavy water plants. The number of entrained eggs and larvae with all these facilities operating would be several times greater than those listed for the two Bruce A units alone. Both the Nanticoke and Bruce station intakes are located offshore, approximately 10 metres below the surface. However, it is likely that the very large water requirements of these stations results in the withdrawal of a substancial portion of the cooling water from the nearshore zone where larvae concentrations may be high.

Data are also available on the numbers of larger fish impinged on intake screens at steam-electric stations. Table D.1 lists impingement quantities recorded and/or estimated for some stations operated by Ontario Hydro (10). The impinged fish were primarily alewife, gizzard shad, rainbow smelt and deepwater sculpin.

From a series of biological investigations to improve once-through cooling system designs for the great lakes it was found that:

> "Existing cooling water intakes have potential to entrap large numbers of impingeable fish which could interfere with the operational reliability of the cooling system and represent a possible ecosystem impact in terms of loss of reproductive potential" (11).

Several of the sections that follow identify concern for protection of the nearshore or littoral zone of large freshwater lakes and reservoirs. The nearshore zone is defined for the purpose of this code as that part of the water body between the shoreline and the point where the water depth is the greater of:

(i) double the local Secchi disk reading in the vicinity of the intake and outfall and in the areas epected to be influenced by the thermal plume, or

(ii) 10 metres.

TABLE D.1 ANNUAL FISH IMPINGEMENT AT GENERATING STATIONS IN ONTARIO (KILOGRAMS) (10)

	Station				
Year	Lakeview	Hearn	Pickering	Nanticoke	Lennox
1973			130 300	1 500	
1974	24 000	19 000	232 400	890	
1975	34 600	21 300	328 800	2 600	
1976	1 900	12 600	50 400	2 000	1 40

For this purpose a Secchi disk reading (12) or average of several readings taken during the period July to August should be used. This is a period of high biological productivity of littoral zone zooplankton and ichthyoplankton (11, 12).

D.3.3 Small Freshwater Lakes and Reservoirs

For the purposes of this environmental code, a small freshwater lake or reservoir is defined as a lake or reservoir from which a large percentage of the total water volume is withdrawn annually for power plant cooling purposes.

There are numerous types or subcategories of small freshwater lakes and reservoirs. This subcategorization depends on factors such as the annual amount of flow through the water body, stratification or non-stratification, shape, and depth-area distribution (13). Both the volume and average annual outflow determine the degree to which power plant cooling systems operating on small water bodies behave as once-through or recirculating cooling systems. As these volume and flow-through capacities decrease in relation to the cooling water volume and flow rate, the lake or reservoir begins to function more and more as a closed-cycle cooling system.

Several on-stream cooling reservoirs in operation in Canada today would be considered semi-recirculating systems. During a short period of the year (usually during spring runoff) there is often a substantial release rate from these reservoirs while during the remainder of the year the release rate is less than the blowdown release that would occur from cooling towers or an offstream artifical cooling pond.

Another element in the categorization of small freshwater bodies is the level of biological activity in intermittent or small continuous streams prior to the construction of an on-stream cooling reservoir. For instance, native fish populations in some small intermittent streams may be considered insignificant or non-existent. A small reservoir on such a stream is likely to be a considerable improvement in terms of recreational use potential (including fishing), even if designed and operated primarily for cooling purposes. Such a system might be "dedicated" by a province as "single purpose for power plant cooling", and any fish populations introduced to the system as a secondary benefit would not necessarily be afforded the same level of protection as provided to fish in a natural small freshwater lake, or a small reservoir constructed on a stream or river with a significant native fish population. A small reservoir which does not receive adequate inflow from an intermittent stream to satisfy annual water makeup requirements is essentially a closed-cycle cooling system. Some make-up water would be supplied from another source, such as the river into which the intermittent stream drains, and the reservoir would blowdown at a rate comparable to an artifical offstream cooling pond.

A set of criteria has been developed by the U.S. Environmental Protection Agency (14) for determining whether a man-made lake would be deemed best available demonstrated technology (BADT) or best available technology economically achievable (BATEA) for steam electric power plant cooling. These criteria specify the following:

(a) an environmental test, requiring that both the construction and operation of the impoundment or water body be acceptable in terms of effects on municipal water supplies, shellfish beds and fishery areas (including spawning and breeding areas), wildlife, or recreational areas;

(b) a thermal efficiency test, requiring that the discharge from the water body, on a long-term average annual basis, contains no more than 2% of the waste condenser heat passed to the cooling water body; and

(c) a recirculation requirement establishing a flow restriction limiting the total discharges from the water body, on a long term average annual basis, to no more than 100 cubic feet per second (approximately 3 m^3/s) per thousand megawatt generating capacity (nameplate capacity) of the facility.

For the purpose of this environmental code, the criteria for designating a reservoir a recirculating cooling system not subject to the once-through cooling recommendations are:

(a) the aquatic life residing in or migrating through the stream prior to creation of the impoundment is of minor signifiance, and

(b) the average annual discharge from the impoundment is not greater than 3 m^3/s per 1000 MW of installed generating capacity.

Recommendations contained in this appendix (series 100) relating to cooling water withdrawal, intake and outfall design and location, damage to entrained organisms, and heated discharges, are not applicable to small lakes and reservoirs meeting the criteria (a) and (b) above. Discharge from such systems would be considered "recirculating cooling system blowdown" and subject to the recirculating cooling system recommendations. The criterion of 3 m^3/s per 1000 MW is approximately equal to the maximum blowdown expected from a recirculating cooling system, or about 10% of the circulating water flow at a fossil-fuelled power plant.

Some of the environmental concerns with operating power plant cooling systems on small freshwater lakes and reservoirs are similar to the concerns with large water bodies. As with large water bodies, the shallow nearshore zone is vital to the biological well-being of the system. Large withdrawals from or large heated discharges to this zone may have serious detrimental effects. There are, however, additional environmental concerns to be considered in the smaller systems. Some of these are:

- the water volume in the nearshore zone represents a larger percentage of the total lake volume;
- the cooling water withdrawals are a larger percentage of the total lake volume;
- the hypolimnion is more susceptible to depletion by volume withdrawal;
- heated discharges may affect large portions or all of the water body;
- higher temperature zones of thermal plumes may extend across to the opposite shore, interferring with fish movement or migration.

D.3.4 Rivers

Rivers typically have markedly different physical and biological characteristics than lakes or reservoirs (13, 15). These characteristics include:

- unidirectional, variable velocity, turbulent flow with rapid vertical mixing and minimum temperature stratification;

- variable horizontal mixing depending on width to depth ratio and flow pattern;
- high seasonal variability in flow;
- low-flow in warm summer months;
- high surface area to volume ratio;
- lower biological productivity than natural lakes and ponds due to short residence times in any particular reach of a river;
- fish migration and spawning runs.

The nearshore areas of larger rivers are usually biologically more productive than the deeper core section where most of the flow is conveyed. The shallower, lower velocity inshore areas often provide favourable conditions for fish spawning, and the feeding and growth of larvae and fry (16, 17).

Primary concerns associated with operating cooling systems on rivers, in addition to those associated with nearshore waters, are the low flow rate in the river relative to cooling system withdrawal and discharge rates, and the ability of fish to avoid the intake and thermal plume.

D.3.5 Estuaries

An estuary is the portion of a river near its mouth that is influenced by ocean tides. A typical estuary can be divided into a salinity intrusion region and a freshwater tidal region (18). The longitudinal extent of the salinity intrusion varies with the amplitude of the tide and the freshwater inflow into the estuary.

Estuaries are areas of high biological productivity. Many commercially important fish species depend on the highly productive phytoplankton and zooplankton populations in estuaries for food. Estuaries are used by many of these species for spawning, early development and growth during portions of their life history. It has been estimated (19) that 63% of the commercial catch of fish and invertebrates in the Atlantic Ocean consists of species dependent on estuaries.

Power plant once-through cooling systems operating on estuaries can have serious and widespread affects on aquatic populations. Not only is there typically a high density of aquatic life, but that life can be repeatly subjected to the dangers of impingement and entrainment because of the frequent reversals in water movement in the estuary. For these reasons, it is assumed that the siting criteria for new steam electric power stations in Canada (now under development for inclusion in the Siting Phase Code) will preclude once-through cooling systems in estuaries. Hence, once-through cooling system location or environmental design recommendations addressing concerns specific to estuaries are not considered further in this document.

D.3.6 Marine

Many of the environmental concerns associated with operating once-through cooling systems on ocean sites are similar to the concerns in large freshwater lakes and reservoirs. Although the ocean is basically an infinite source of water and an infinite heat sink, the coastal regions which support the aquatic life in oceans have a much more finite dimension. Ocean littoral zones are highly productive biologically, although not normally as productive as estuaries (20). Important factors are the distribution of aquatic species in the nearshore coastal areas where power plants might be located, and their susceptibility to damage from impingement, entrainment and heated discharges.

The factors that distinguish ocean sites from large freshwater lake or reservoir sites include the following:

- the photosynthetic zone, ranging from 0 to 80 metres in depth, is not as sharpely marked as in a lake;
- different aquatic species reside in the ocean coastal reaches with different tolerances to chemical and physical stresses and heat;
- coastal areas are subjected to diurnal water level fluctuation which will affect the movement and residence times of aquatic species in waters affected by cooling system operation;
- the range and daily and seasonal variation in water temperature may be different;
- current and wave action are usually greater.

D.4 Minimization of Numbers of Aquatic Organisms Entrapped, Impinged and Entrained

D.4.1 General

A number of measures can be taken to minimize the entrapment, impingement, and entrainment of aquatic organisms in once-through cooling systems. These include:

- reducing the withdrawal of water from areas in the source water body containing high concentrations of aquatic organisms;
- use of barriers and other deterents to help organisms avoid entrapment in the intake flow stream;
- diversion and return in viable condition to the source water body of organisms that are entrapped in the intake flow stream.

The methods by which these can be achieved are discussed in the following sections and recommendations are presented.

D.4.2 Minimization of Intake Volume

(a) General Cooling Water Withdrawal Limitations. As previously discussed, the number of aquatic organisms entrapped, impinged and entrained by power plant cooling systems is directly proportional to the volume of water withdrawn from the source water body. The most effective way to ensure that system-wide effects do not occur because of cooling water withdrawal is to limit the volumes withdrawn from either the littoral zone, the entire system, or both.

As discussed in Section D.3, the shallow nearshore or littoral waters of most water bodies are generally the most biologically productive. The amount of cooling water taken from the nearshore will depend on the intake configuration and distance offshore, the cooling water withdrawal rate, the persistency of longshore currents, the amount of nearshore/offshore exchange, and other factors. In large water bodies, for instance, there is a tendancy for longshore currents to persist, often for several weeks, during the summer period when the concentrations of relatively immobile organisms such as fish larvae are generally highest (21, 22).

For comparative purposes, the amounts of littoral zone longshore flow that a 4000-MW nuclear station might remove from a typical large water body are listed in Table D.2. The total station cooling water requirement is assumed to be 225 m^3/s. With an assumed average distance offshore of 1 km to reach the minimum littoral zone depth of 10 m, and an average longshore current velocity of 10 cm/s (22), the average longshore flow rate is 500 m^3/s.

As indicated in Table D.2, a high percentage of the total longshore flow within the littoral zone could pass through a power plant's cooling system. When 100 percent of the cooling water supply comes from the nearshore, 45 percent of the longshore flow within the nearshore zone enters the intake (or all water from the shoreline to 700 m offshore). Further calculations show that if only 50 percent of the 4000-MW station's cooling water requirement was drawn from the 1-km wide littoral zone, the station could pass the total volume of water in a 50 km long littoral zone reach through its cooling system in less than 12 days (for this to occur, the average longshore current over the period would have to be less than 10 cm/s). Several generating stations in series along a shoreline could, of course, compound the effect because of re-entrainment of water discharged from upcurrent stations.

TABLE D.2 USE OF LITTORAL ZONE LONGSHORE FLOW TO SUPPLY COOLING WATER (C.W.) FOR A 4000-MW NUCLEAR STATION

Rate of Withdrawal from Littoral Zone (m^3s)	Percent Total C.W. Supply	Percent of 500 m^3/s Longshore Flow
225	100	45
169	76	34
112	50	22
90	40	18
68	30	14
45	20	9
22	10	4

Any numerical limit on the withdrawal of cooling water from the nearshore zone is by nature somewhat arbitrary. However, such a limit provides protection that may not otherwise be achieved through selection of intake location and design alone. For example, where large withdrawals are involved, intakes located beyond the nearshore zone may withdraw a substantial volume of water from the nearshore zone. This is discussed further in section D.4.3 (b). A limit on withdrawal from the nearshore zone would mean that such considerations would be taken into account when siting an offshore intake. It is considered that suitable baseline protection for annual fish larval crops would be provided for most water bodies by limiting the withdrawal of water from the nearshore zone to 10 percent of the volume within that zone during the period May 1 to August 31, when larval fish populations are normally highest.

In source water systems where large water withdrawal from beyond the littoral zone is likely to also cause concern, an additional limitation related to total volume or total flow in the water body must be considered. In freshwater lakes and reservoirs a baseline level of protection would be provided by limiting the total annual withdrawal to less than five percent of the total volume of the water body. This is based on the premise that when the total water intake volume on a given freshwater system exceeds five percent of the total system volume, a very real probability exists of system-wide effects over an extended time period. Because of the time and spatial distribution of water intake from a system, a five percent withdrawal on an annual basis infers high proportional withdrawals in specific areas and during specific time periods.

The five percent criterion would mean, for example, that the approximate cooling water intake volumes and installed generating capacities listed in Table D.3 for a number of arbitrarily selected water bodies in Canada could not be exceeded.

In rivers fish larvae and fry being displaced down river from spawning grounds may be fairly evenly distributed across the flow steam. To minimize entrainment losses, cooling water withdrawal must be limited to an acceptable fraction of the entire river flow. Ensuring that the cooling water intake rate does not exceed 10 percent of the river flow rate would provide a suitable baseline level of protection.

Based on the foregoing considerations, the following general cooling water withdrawal limitations are recommended:

Recommendation R101. ***Unless it is demonstrated that larger withdrawals are no more detrimental environmentally, the volume of cooling water withdrawal should be such that:***

(i) in all water body types, the total water withdrawal (all sources) during the period May 1 to August 31 from the 50 km (or shorter) reach of nearshore waters on which a station is centered does not exceed 10 percent of the normal standing volume of that reach during that period;

(ii) in lakes and reservoirs the total annual water withdrawal (all sources) does not exceed 5 percent of the total volume of the water body;

(iii) in rivers, the total rate (all sources) of water withdrawal at any time from the 50 km reach of river upstream from the generating station does not exceed 10 percent of the flow at that time in that reach of the river.

Part (i) of this recommendation limits the withdrawal of water from the nearshore zone of all water body types (lakes, reservoirs, rivers, oceans). Parts (ii) and (iii) are additional provisions which limit the total withdrawal or withdrawal rate from lakes and reservoirs and from rivers respectively.

For a shoreline intake all of the water withdrawn will come from the nearshore zone. However, for an offshore intake the amount of water withdrawn from the nearshore zone will depend on the distance from the nearshore zone, longshore currents, and other factors. An environmentally designed submerged intake located beyond the nearshore zone will not be subject to R101 (i). With respect to R101, an offshore submerged intake will be considered to be environmentally designed if the majority of the water withdrawn comes from beyond the nearshore zone. The origin of the water withdrawn for a specific intake location can be estimated by hydraulic modelling studies. Other environmental aspects of intake design and location are discussed in sections D.4.3 and D.4.4 (R105, R106, R107, R109).

TABLE D.3 LIMITING COOLING WATER INTAKE RATES AND INSTALLED CAPACITY FOR MEETING THE FIVE PERCENT WITHDRAWAL CRITERION

Lake or Reservoir	Lake or Reservoir Volume ($m^3 \times 10^9$)	Limiting C.W. Intake Rate (m^3/s)	Limiting Installation (MW)		Present & Planned Installation (MW)	
			Fossil	Nuclear	Fossil	Nuclear
Lake Ontario	1 638	2 596	86 500	46 400	8 810	9 620
Lake Erie	458	726	24 200	13 000	12 200	-
Lake Huron	3 539	5 608	186 900	100 100	120	6 040
Lake Superior	11 920	18 889	629 600	337 000	1 410	-
Lake Nipigon	227	360	12 000	6 400	-	-
Lake Winnipeg	362	574	19 100	10 200	-	-
Lake Manitoba	28	44	1 470	790	-	-
Diefenbaker Lake	5	8	270	140	600	-
Lake Wabamun	0.5	0.7	24	13	580	-
Wollastan Lake	36	57	1 900	1 020	-	-

A small lake or reservoir designated a recirculating cooling system according to criteria discussed in section D.3.3 is not subject to recommendation R101.

Total withdrawal volume and total rate of withdrawal are determined by combining the cooling water withdrawn for the proposed new generating station with water drawn from the specified reach by all other intakes.

(b) Recirculating Cooling Systems. It is evident that concerns with entrapment, impingement and entrainment can be considerably reduced by the use of recirculating or closed-cycle cooling systems, since these systems reduce the intake to a fraction of that required for once-through systems. The assumption that once-through condenser cooling systems will still be used at some new or expanded steam electric stations is based on the premise that measures can be taken to minimize the numbers of fish entering these systems and/or that the organisms entrained will survive the stresses of passage through the cooling system.

With once-through auxiliary cooling systems the same potential to minimize the numbers of organisms entrapped, impinged and entrained exists; however, the probability of entrained organisms surviving passage does not. With the pumps and distribution network in most auxiliary cooling water systems, total mortality of entrained eggs and larvae from physical effects, chemicals, or high temperature is almost certainly assured. Hence, special consideration must be given to fish entrainment by once-through auxiliary cooling system.

An assessment was carried out to determine the relative contribution by auxiliary cooling water systems to total plant entrainment losses with different assumed rates of mortality in the condenser cooling water system. The results are presented graphically in Figure D.5. The contribution of the auxiliary cooling system to total station entrainment mortality at a typical CANDU nuclear station (aux. c.w. 12 percent of c.c.w.) and a typical fossil-fuelled station (aux. c.w. 5 percent of c.c.w.) are summarized in Tables D.4 and D.5 respectively.

The data provided in these tables suggests that if entrainment mortality is low in the condenser cooling water, the auxiliary cooling water can contribute a significant portion of the total entrainment mortality.

The following measures are recommended to minimize the adverse environmental effects of auxiliary cooling systems:

TABLE D.4 CONTRIBUTION OF AUXILIARY COOLING WATER SYSTEM TO TOTAL ENTRAINMENT MORTALITY AT A TYPICAL CANDU NUCLEAR STATION

Percent Mortality in Condenser Cooling	Percent Contribution to Total Entrainment Mortality	
	Condenser Cooling	Auxiliary Cooling
10	45	55
20	62	38
30	71	29
40	77	23
50	80	20
60	83	17
70	85	15
80	87	13
90	88	12
100	88	12

***Recommendation R102.* Auxiliary cooling water systems at steam electric generating stations should:**

***(i)* be designed to minimize water intake to the degree practicable;**

***(ii)* be designed to accommodate maximum practicable reuse of discharge water for other plant processes.**

(c) Temperature-Volume Trade-Off. Next to recirculating cooling systems, temperature-volume trade-off opportunities offer the greatest potential to minimize cooling water intake volume. Once-through condenser and once-through auxiliary cooling systems should be operated at the maximum temperatures technically feasible and environmentally acceptable to reduce water intake.

From an operational standpoint, there are limits on how high the condenser temperature rise can go before serious reductions in power plant efficiency occur. The graph in Figure D.6 (23) shows that the power output at Pickering G.S. would decrease 1.3 percent with an increase in condenser temperature from 8.3°C to 13.9°C and 5.6 percent with a rise from 8.3°C to 22.2°C. Hence, the volume reduction technically feasible may

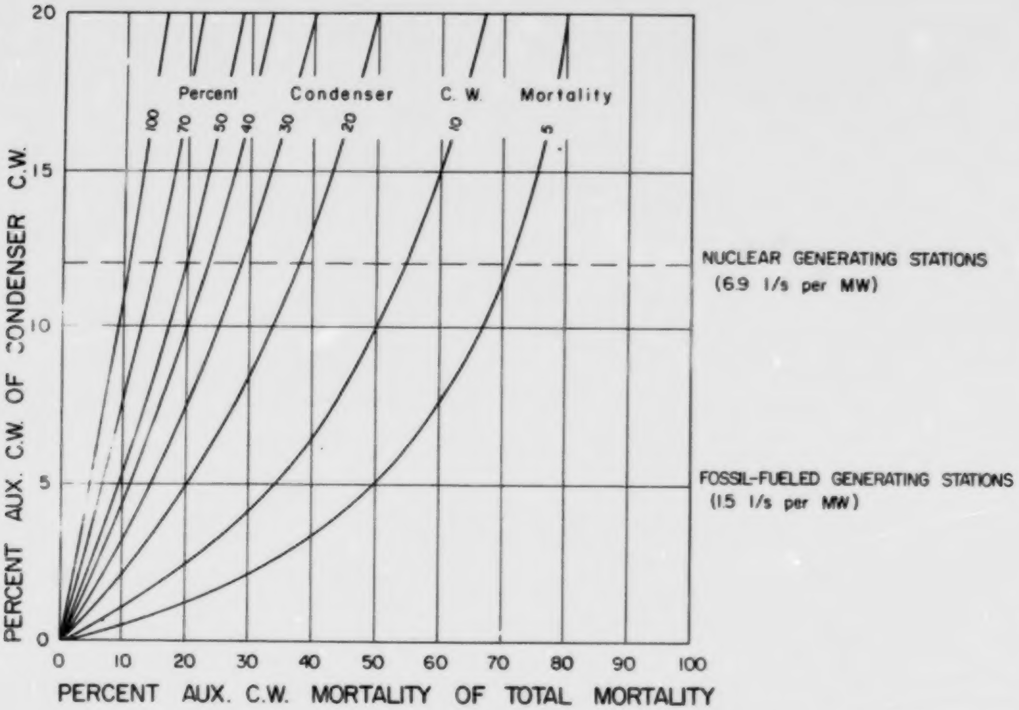


FIGURE D.5 CONTRIBUTION OF AUXILIARY COOLING WATER SYSTEM TO TOTAL STATION ENTRAINMENT LOSSES

be quite limited at some stations. However, even relatively small increases in temperature of 15 or 20 percent will result in an equivalent percentage reduction in entrained fish and should be considered in the plant design.

The biological constraint on condenser temperature rise is the temperature tolerance level of the fish species entrained. This aspect is discussed further in Section D.5.4 where temperature limitation recommendations are presented.

(d) Pump Selection. The maximum condenser temperature rise feasible for biological reasons will change during the year depending on the temperature tolerance of the entrainable species of ichthyoplankton present (see Section D.5.4). Environmental benefits can be realized by adjusting the cooling water flow during the year to suit prevailing conditions. Flexibility to do this may be obtained by selecting the appropriate number and size of pumps. Two or three small pumps plus one standby pump per unit will provide more flexibility than one large pump plus a standby. This flexibility in number of pumps used will also reduce pumping costs in winter, when colder water is available, without reducing the station electrical output.

TABLE D.5 CONTRIBUTION OF AUXILIARY COOLING WATER SYSTEM TO TOTAL ENTRAINMENT MORTALITY AT A TYPICAL FOSSIL-FUELLED STATION

Percent Mortality in Condenser Cooling	Percent Contribution to Total Entrainment Mortality	
	Condenser Cooling	Auxiliary Cooling
10	66	34
20	79	21
30	85	15
40	88	12
50	90	10
60	92	8
70	93	7
80	94	6
90	95	5
100	95	5

In addition to ensuring flexibility by pump selection, further control of the cooling water flow rate can be obtained with the use of throttling valves. Large automated butterfly valves are often installed at the downstream end of condensers so that flow can be controlled to maximize plant thermal efficiency (24). The probability of increased entrainment mortality from operating pumps at possibly lower efficiency, as well as the economic and plant efficiency implications, should be considered in the selection of flow control features.

Based on the foregoing, the following control measures are recommended:

Recommendation R103. ***Flexibility of, and control over, the cooling water flow rate through each condenser by appropriate selection of the number and size of cooling water pumps and the provision of throttling capability, should be considered.***

(e) Planned Maintenance Outages. Confined periods or seasons of the year when the potential loss by entrainment damage is of greatest concern can usually be identified. Since power plant generating units also typically undergo a planned maintenance outage for a period of one month or more each year, an opportunity is presented for reducing substantially the total number of ichthyoplankton entrained annually by selectively timing volume reduction. For instance, with a typical distribution of alewife larvae

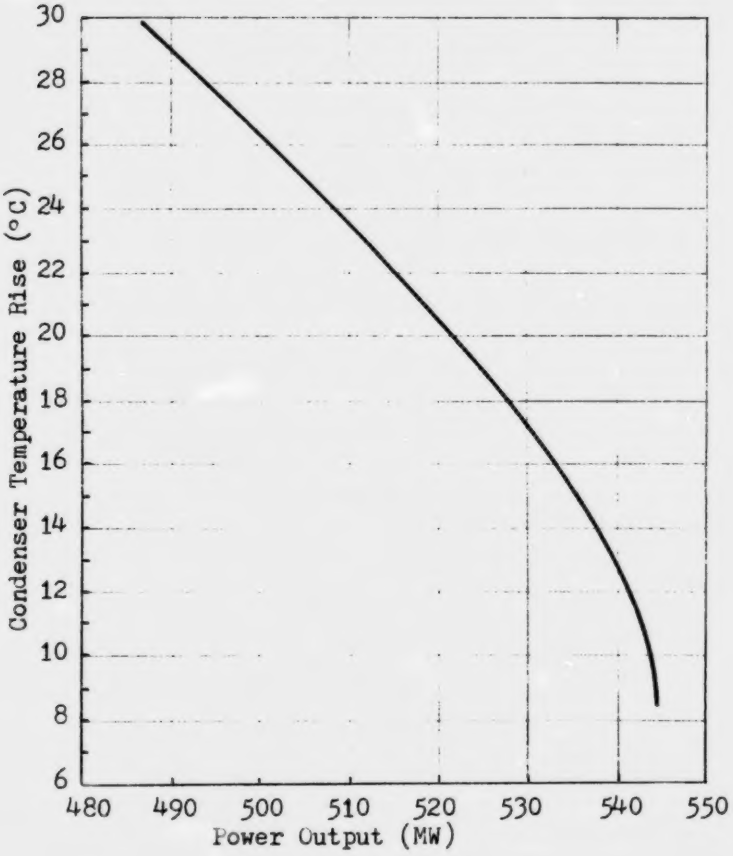


FIGURE D.6 RELATIONSHIP BETWEEN POWER OUTPUT AND CONDENSER TEMPERATURE RISE (adapted from reference 23)

concentrations (25), a shutdown for the month of July would reduce the annual number of larvae entrained by 63 percent.

It is recognized that the highest larvae concentration period may not coincide with the period when entrainment will cause the greatest population loss. Naturally low survival rates for very young larvae, greater entrainment avoidance potential of more advanced life stages, and higher percentage mechanical damage to larger organisms are all contributing factors in determining the period when a planned outage would be most advantageous to aquatic populations.

In well designed intake systems where larvae and fish entrainment is not a problem scheduling of outages will not be an important environmental factor.

Since properly scheduling of planned outages has the potential for substantially reducing total entrainment losses, whether it be from mechanical, chemical or temperature mortality, the following control measure is recommended:

Recommendation R104. ***Planned outages of power plant units should be scheduled, whenever practicable, to coincide with the period of highest concern for ichthyoplankton (fish egg and larvae) entrainment.***

D.4.3 Selection of Intake Type and Location

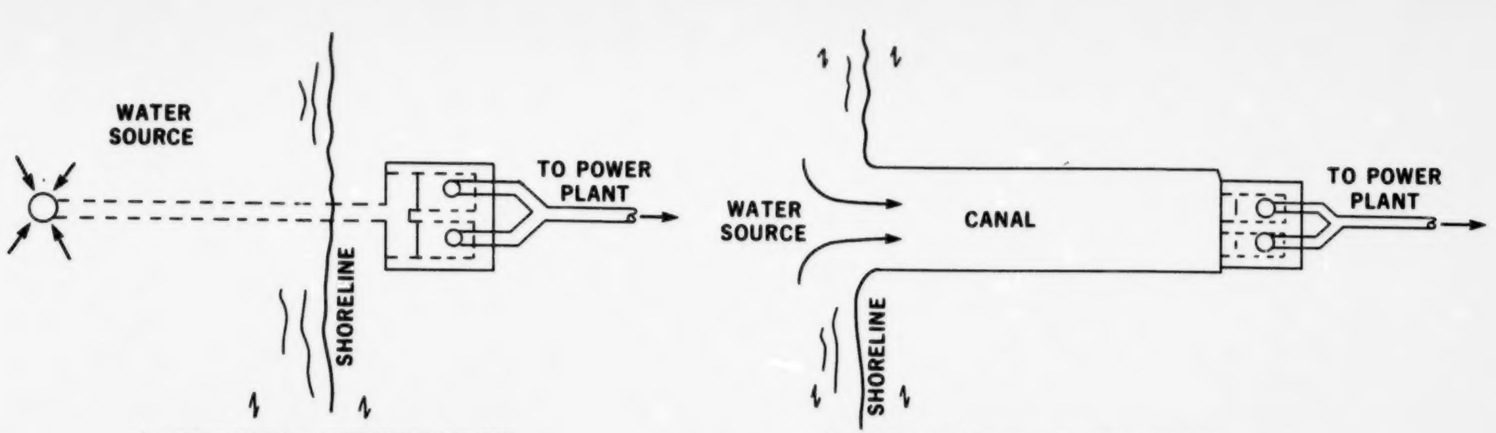
(a) Description of Intake Types. Within a power development site selected to meet the criteria defined in the Siting Phase Code, the intake type and location is governed by the quantity of cooling water to be withdrawn, the hydrographic and environmental conditions of the source water body, the geological and topographical conditions of the shoreline, bank and bottom, and engineering and economic constraints.

Intakes for the once-through cooling water supply to steam electric generating stations can be categorized as follows:

- offshore submerged,
- shoreline, and
- approach channel.

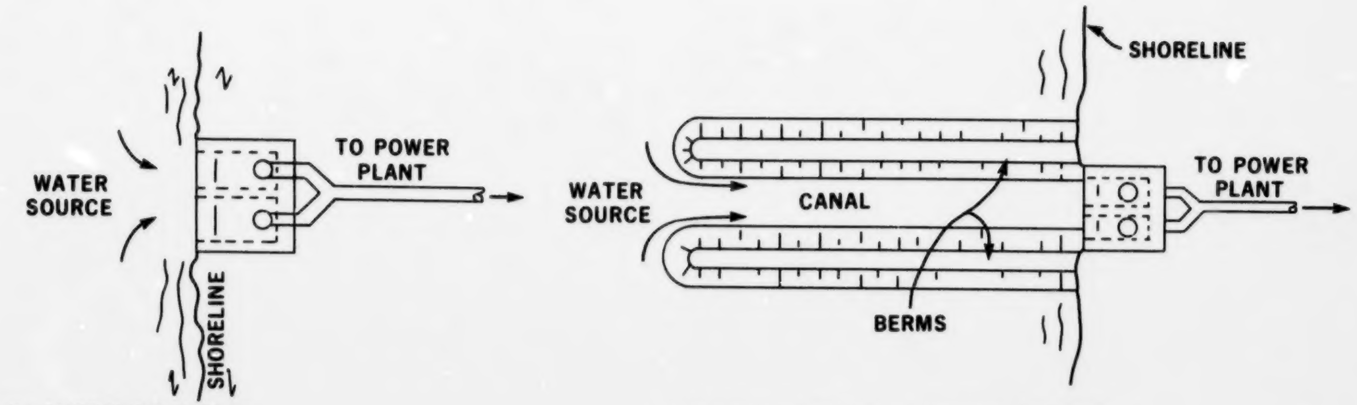
Each of these types is shown schematically in Figure D.7 and described briefly below.

A common type of cooling water intake is a submerged intake located some distance offshore as shown in Figure D.7a. This type of intake involves offshore construction of an inlet structure connected to a long conduit or tunnel leading to a forebay at the shoreline or further inland where a forebay, screen and pump well are located. It is often used where the bank slope is not steep and lateral movement of the


WATER SOURCE
SHORELINE
TO POWER PLANT
WATER SOURCE
CANAL
SHORELINE
TO POWER PLANT

(a) OFFSHORE SUBMERGED INTAKE

(c) APPROACH CHANNEL INTAKE-INLAND


WATER SOURCE
SHORELINE
TO POWER PLANT
SHORELINE
WATER SOURCE
CANAL
BERMS
TO POWER PLANT

(b) SHORELINE INTAKE

(d) APPROACH CHANNEL INTAKE-OFFSHORE

FIGURE D.7 SCHEMATICS OF TYPICAL COOLING WATER INTAKES (15)

water edge is significant between high and low water. Offshore intakes are also used to resolve problems with ice, wave action and excess sedimentation. They enable water to be drawn from a lower level where the water temperature is generally cooler, hence improving the plant thermal efficiency. They also offer the environmental advantages of withdrawing water from beyond the littoral zone.

Shoreline cooling water intakes are generally combined systems of inlet, screen and pump well in single structures located at or near the shoreline as shown in Figure D.7b. A shoreline intake is often used where the bank slope is relatively steep, where movement of the water edge between high and low water is relatively small, and where ice control, excessive sedimentation or wave action are not a problem.

Recessed or protruding intakes (Figures D.7c and d) are often used for technical reasons such as easier inland construction of the screen and pumpwell structure, lower head loss along a canal than along a conduit, control of heated water recirculation by separating the intake from outfall, or prevention of ice or wave damage.

(b) Intake Location Relative to High Productivity Waters. To minimize the withdrawal of water from areas of high biological productivity, intakes can be located offshore beyond the littoral zone. The farther the intake is moved offshore into deeper waters, the narrower the band of longshore moving current affected and the smaller the withdrawal of nearshore waters, as illustrated in Figure D.8.

Although protection of the nearshore waters is normally the primary concern, a shoreline intake may be no more environmentally detrimental in particular situations. A river in which the entrainable fish are evenly distributed throughout the flowstream and a shoreline intake offers the greatest potential for incorporating fish entrapment, impingement and entrainment avoidance features is an example. If it can be demonstrated at a particular site that an alternative to the offshore intake offers a net advantage environmentally, such an alternative would be acceptable and, in fact, preferred. However, such situations are expected to be exceptions and nearshore zone protection the more common concern.

Hence, the following recommendation, applicable to all water body categories, is designed to minimize the volume of cooling water withdrawn from nearshore waters:

Recommendation R105. ***Intakes should be located offshore beyond the littoral zone unless it is demonstrated that locating the intake within the littoral zone is biologically more acceptable.***

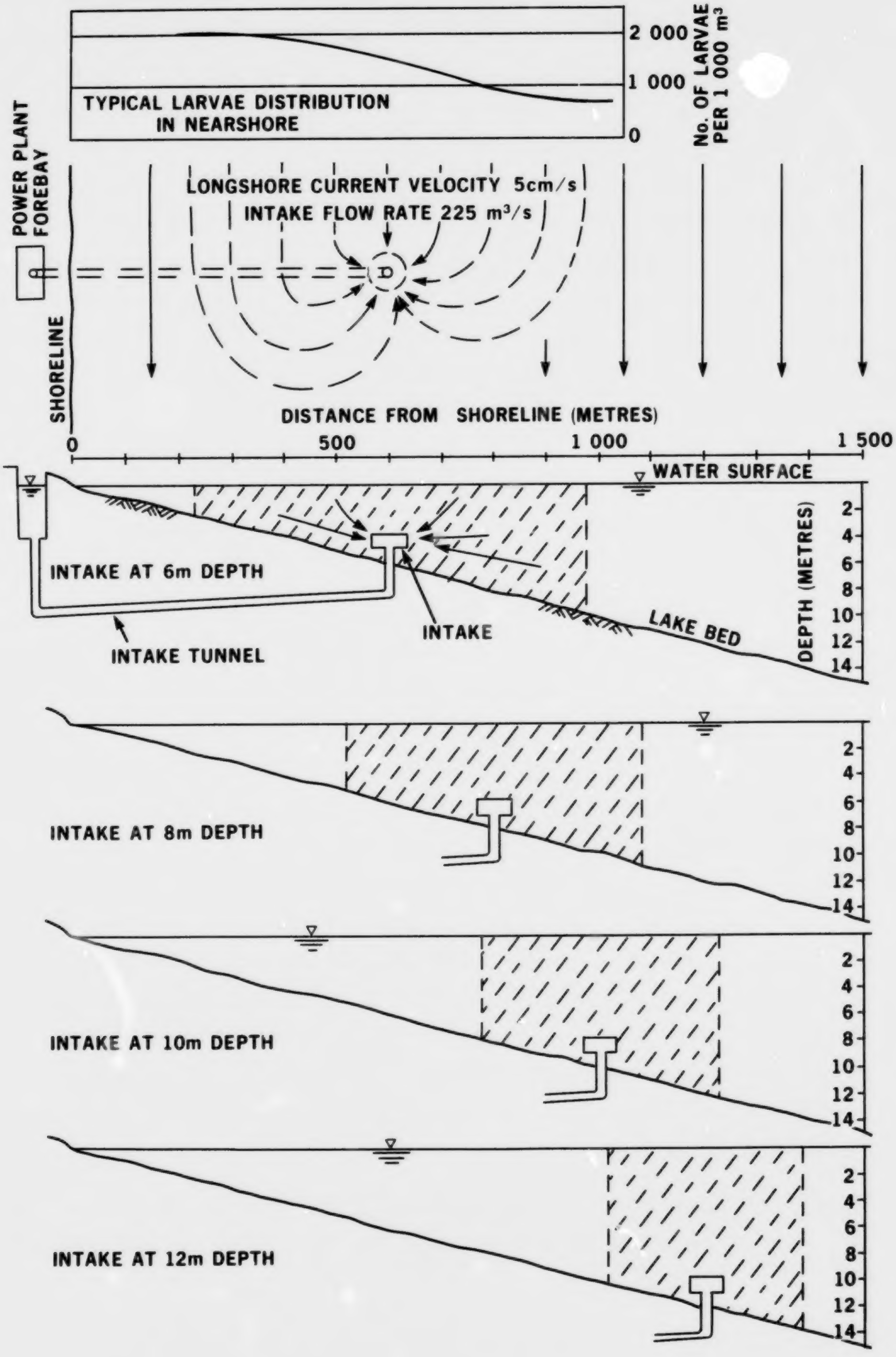

TYPICAL LARVAE DISTRIBUTION IN NEARSHORE
2 000
1 000
0
No. OF LARVAE PER 1 000 m³
POWER PLANT FOREBAY
LONGSHORE CURRENT VELOCITY 5cm/s
INTAKE FLOW RATE 225 m³/s
SHORELINE
DISTANCE FROM SHORELINE (METRES)
0
500
1 000
1 500
WATER SURFACE
INTAKE AT 6m DEPTH
INTAKE
INTAKE TUNNEL
LAKE BED
DEPTH (METRES)
2
4
6
8
10
12
14
INTAKE AT 8m DEPTH
INTAKE AT 10m DEPTH
INTAKE AT 12m DEPTH

FIGURE D.8 RELATIVE EFFECTS ON NEARSHORE WATERS OF INTAKES AT DIFFERENT DISTANCES OFFSHORE

(c) Intake Location Relative to Outfall. The location and positioning relative to each other of individual component features of a power station cooling system, particularly the cooling system intake and outfall, is often referred to as the cooling system general arrangement. Intakes are normally positioned to avoid recirculation of the heated cooling water from the outfall to the intake since higher temperature intake water can reduce the thermal efficiency of the station.

To maintain a high thermal efficiency, and perhaps to maintain the condenser discharge temperature within prescribed effluent limits, a station with thermal plume recirculation may have to pump additional cooling water. Alternatively, the station may be de-rated and additional generating capacity may be required from another station in the system. In general, thermal plume recirculation will require additional cooling water volume somewhere in the system with the attendant damages to aquatic organisms that are entrained.

During the cooler months, the elevated temperature of the cooling water discharge attracts fish whose swimming ability is reduced at the low ambient temperatures. If part of the thermal plume returns toward the intake, many of these lethargic fish will swim along with it and be drawn into the intake. The likely result of such thermal plume recirculation will be an additional man-made component of fish mortality in the aquatic ecoystem. Hence, there is both an operational and an environmental justification for minimizing recirculation of the thermal plume.

Some intentional recirculation of cooling water to control ice problems in the intake is often practised at generating stations in Canada. This is acceptable provided that the warm water injection is well controlled and localized to the area requiring control.

Where there is a predominant current direction, locating the intake upcurrent from the outfall will minimize recirculation. Where no such direction is evident, the intake can be separated from the outfall by sufficient distance to allow an acceptable amount of plume cooling to take place before the plume reaches the intake area.

Density differences between the ambient water and the thermal plume can assist in minimizing recirculation. Since the thermal plume generally will spread over the surface of the receiving water body (i.e., in the epilimnion), an intake located in the hypolimnion (i.e., below the thermocline) should draw little or none of the plume. This arrangement of intake and outfall should be used only after site studies have concluded that the mixing of these distinct water masses would have no deleterious effects on the biota. In addition, the local depletion of the hypolimnion should not cause significant alterations in the fish populations which inhabit that zone.

If geography permits, separate water bodies could be used to provide an effective separation of the intake and outfall. The chemical and physical characteristics of the two water bodies would have to be studied to ensure that their interaction would not result in environmental degradation. The depletion of one water system and the consequent increase in another may present further environmental problems.

In addition to avoiding uncontrolled heated water recirculation, other environmental factors may influence the relative positioning of the intake and outfall. One particular arrangement to be avoided is an intake located behind the outfall as illustrated in Figure D.9. The outfall, especially if it is a high velocity multiport diffuser, will induce a flow of water from the nearshore zone past the intake towards the outfall. Some of the nearshore organisms in this flow can be intercepted by the intake and subjected to entrainment stresses.

Where lengthy portions of the intake and outfall sections of the cooling system are on land, the elevated temperature exposure time for entrained biota can be minimized by ensuring the station is positioned such that the major portion of the travel time occurs prior to the condenser, as illustrated in Figure D.10.

Based on the foregoing considerations, the following criteria are recommended for relative location of cooling system intakes and outfalls:

Recommendation R106. Unless it is demonstrated that an alternative arrangement is no more detrimental environmentally, the location of a cooling water intake relative to the outfall should be such that:

(a) ***the intake is at a sufficient distance from the outfall and/or in an adequate depth of water to avoid or minimize uncontrolled recirculation of heated effluent in the receiving water body from the outfall to the intake;***

(b) ***if a long water passage on land is required to separate the intake from the outfall, the longer arm of the cooling water passage should be placed on the intake side and the shorter arm on the outfall side.***

D.4.4 Intake Design

(a) General. Although intakes may be located to avoid high fish population areas, significant numbers of fish will normally still be present and susceptible to entrapment, impingement, and entrainment. Environmental features can be incorporated into intake designs both to minimize the number of fish entering the intake and to enable those that do become entrapped and impinged to be safely returned to source water body.

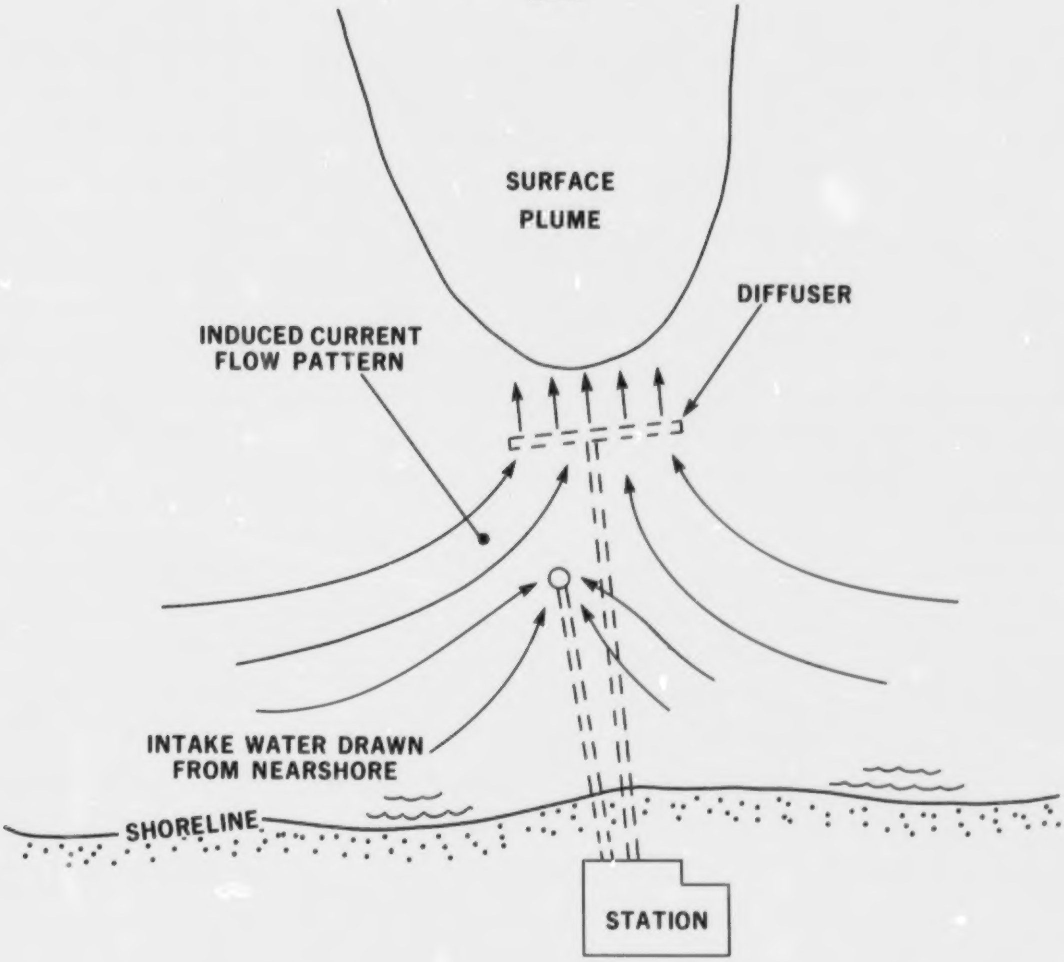

SURFACE
PLUME
DIFFUSER
INDUCED CURRENT
FLOW PATTERN
INTAKE WATER DRAWN
FROM NEARSHORE
SHORELINE
STATION

FIGURE D.9 UNFAVOURABLE INTAKE/OUTFALL ARRANGEMENT

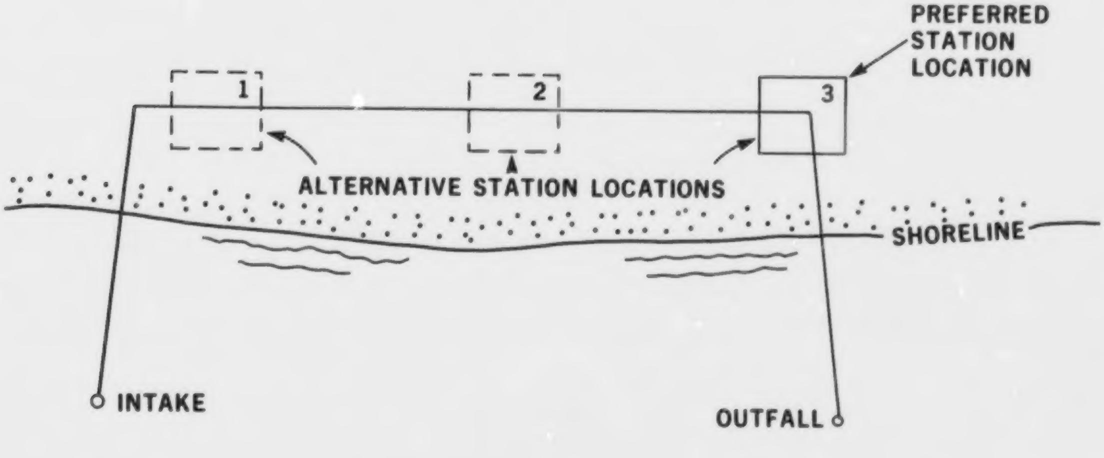

PREFERRED
STATION
LOCATION
1
2
3
ALTERNATIVE STATION LOCATIONS
SHORELINE
INTAKE
OUTFALL

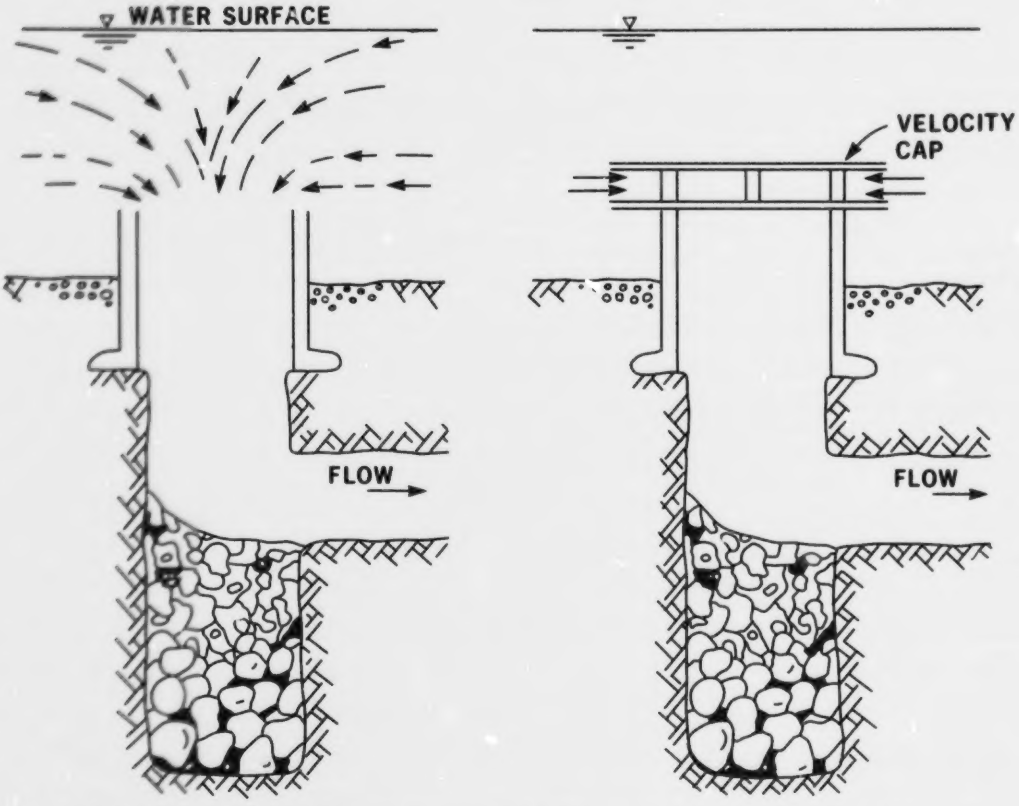
FIGURE D.10 INTAKE/OUTFALL ARRANGEMENT TO MINIMIZE TIME OF EXPOSURE TO EXCESS TEMPERATURE

(b) Intake Design to Minimize Entrapment. Entrapment for the purpose of this code has been defined as the trapping of aquatic organisms in the intake, forebay, or screenwell. Some of the entrapped fish will be small enough to pass through the intake screens while larger fish will be susceptible to entrapment in the forebay and screenwell and impingement on the screens. Impingement of large numbers of fish on the intake screens may result in forced outages of the station (11, 26). The first level of protection is to prevent or discourage both large and small fish from entering the intake.

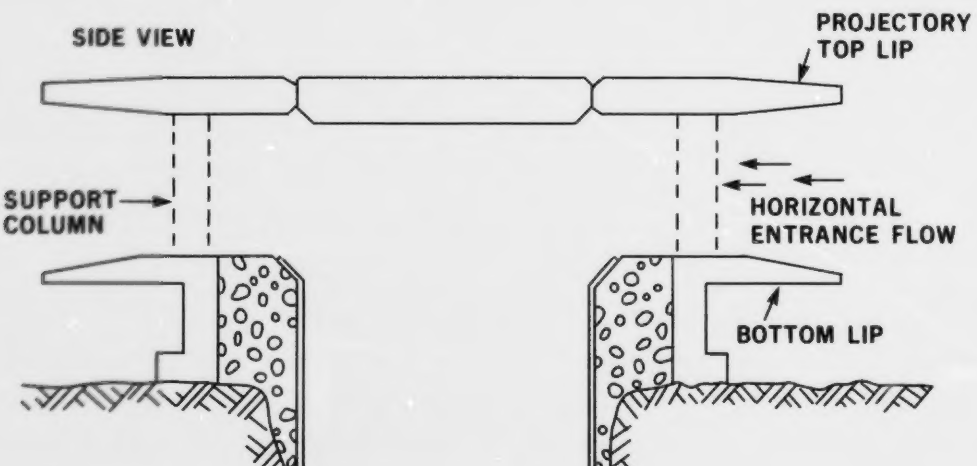
A number of designs and devices have been used (15, 27, 28) to prevent fish entrapment, and numerous others are being investigated. One feature that has proven effective at submerged intakes is a velocity cap. A number of tests and operating records have demonstrated that adult fish can more easily perceive a change in horizontal flow than a change in vertical flow and react to the horizontal flow by swimming away from the intake (29). By placing a cap on the intake, the flow pattern approaching and entering the intake is reoriented to a horizontal direction. Intake flow characteristics with and without the velocity cap are illustrated in Figure D.11a. The velocity cap alone has reduced fish entrapment by about 90% at some operating plants (29, 30).

A horizontal flow pattern entering an offshore submerged intake can best be maintained by positioning the full intake opening above the natural lake or river bottom. Positioning the intake structure in an excavation or natural depression in the lake bottom is undesirable since this orients the approach flow in a vertically skewed direction and provides an area around the intake where fish may congregate.

Studies have shown that many fish remain close to the bottom during the day while at night they may either remain in the lower half of the water column or migrate upward to concentrate near the surface (8, 31, 32). The time spent in transit from the bottom to the surface and back is typically not long, suggesting that intake of water from the middle of the water column may have environmental advantages. Placing the invert (bottom) of the intake opening above the lake bed and constructing a protruding bottom lip provides a physical barrier which helps to minimize entrapment of fish (30, 33) and the inflow of suspended bottom material. Entrapment protection is also improved at a capped intake structure by maintaining a uniform approach velocity to the intake ports (33). The intake design for the Point Lepreau nuclear station, shown in Figure D.11b, incorporates many of the desirable features for an offshore submerged intake. Capped intakes located in depressions in the lake bottom or with openings which do not extend above the lake bed are not considered to be true velocity cap designs.


WATER SURFACE
VELOCITY CAP
FLOW
FLOW

(a) COMPARISON OF AN "OPEN INTAKE" AND A "VELOCITY CAPPED INTAKE"


SIDE VIEW
PROJECTORY TOP LIP
SUPPORT COLUMN
HORIZONTAL ENTRANCE FLOW
BOTTOM LIP
INTAKE TUNNEL SHAFT
INTAKE STRUCTURE

(b) VELOCITY CAP INTAKE DESIGN FOR POINT LEPREAU GENERATING STATION

FIGURE D.11 VELOCITY CAP FOR OFFSHORE INTAKE STRUCTURES (36)

Other environmental designs for submerged intakes may also prove to be effective in minmizing fish entrapment (15, 27, 28, 33, 34). For example, experiments are being conducted (34, 35) with multiple vertical flow ports in a horizontal intake cap (Figure D.12a). A similar intake concept would have a layer of rock of selected sizes distributed over a horizontal grating where the water flows through the voids between the rocks (Figure D.12b) (28). These systems have the advantage of not requiring the substantial vertical depth needed for horizontal flow ports in large intakes. Recent studies indicate that the precast porous veneer intake can be effective in preventing fish entrapment (34, 35). Experiments are also being conducted with porous dike intakes (37, 38).

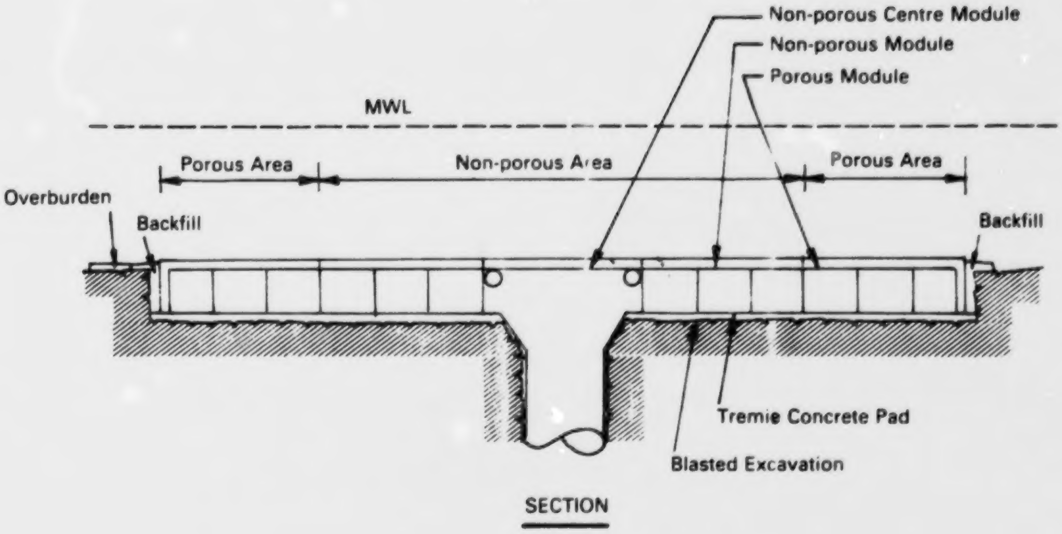
Additional features on submerged intakes may improve their performance. The intake openings at the Nanticoke G.S. on Lake Erie have been recently covered with a wire mesh creating a physical barrier and visual cue which has effectively prevented larger fish from entering the intake (28). This visual cue also permits smaller fish that could physically pass through the mesh openings to detect the intake and avoid being entrapped. A number of other offshore intake design features are being investigated including fine mesh wedge wire drum screens (39) and perforated pipe intakes (40).

One of the behavorial devices currently being tested is strobe (flashing) lights around the intake (28). While a continuous light source will often attract fish, laboratory tests have shown a high avoidance tendancy for strobe lights. However, field tests have shown that strobe lights may not be successful at diverting fish at a shoreline intake (34).

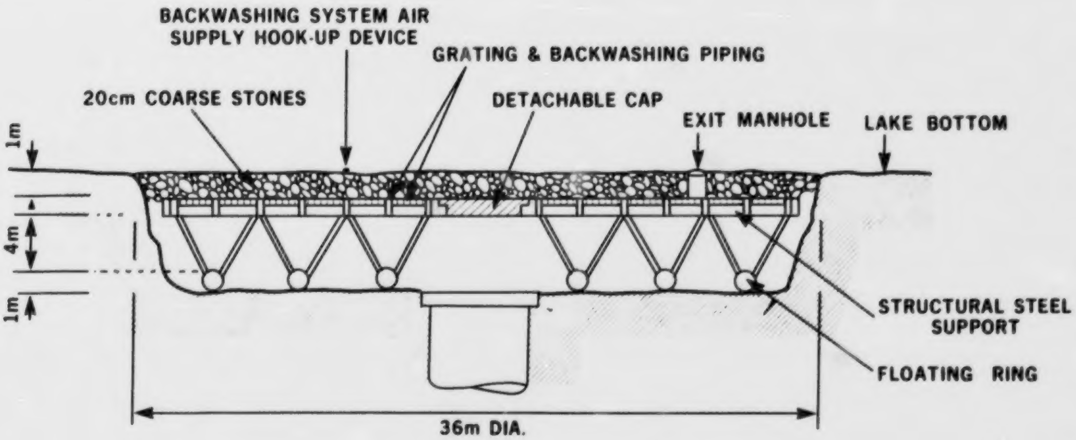
Other guidance systems including cable and chain screens, bubble barriers, electric barriers and sound have exhibited inconsistent performance in past applications (15, 27, 33, 34, 41). Unless demonstrated to be effective these systems alone are not recommended for entrapment prevention at new cooling water intake structures. However, further research and development for intake designs are encouraged.

Recommendation R107. ***Cooling water intakes should be designed to prevent or discourage fish from being entrapped in the flow stream. The design selected for offshore submerged intakes should be demonstrated to be at least as effective in minimizing entrapment of fish as the velocity cap design, for which operating experience is available.***

As indicated in recommendation R105, offshore intakes would not be required if it can be demonstrated that an alternative intake type is no more environmentally detrimental. There are design features for shoreline intakes that will reduce fish


Non-porous Centre Module
Non-porous Module
Porous Module
MWL
Porous Area
Non-porous Area
Porous Area
Overburden
Backfill
Backfill
Tremie Concrete Pad
Blasted Excavation
SECTION

(a) Porous Veneer Type Intake Featuring Multiple Vertical Ports (34)


BACKWASHING SYSTEM AIR SUPPLY HOOK-UP DEVICE
GRATING & BACKWASHING PIPING
20cm COARSE STONES
DETACHABLE CAP
EXIT MANHOLE
LAKE BOTTOM
1m
4m
1m
STRUCTURAL STEEL SUPPORT
FLOATING RING
36m DIA.

(b) Porous Veneer Type Intake Structure Featuring
Porous Rock Multibed Circular Depression Filter Intake (28)

FIGURE D.12 MULTIPLE VERTICAL PORT AND POROUS ROCK INTAKE CONCEPTS

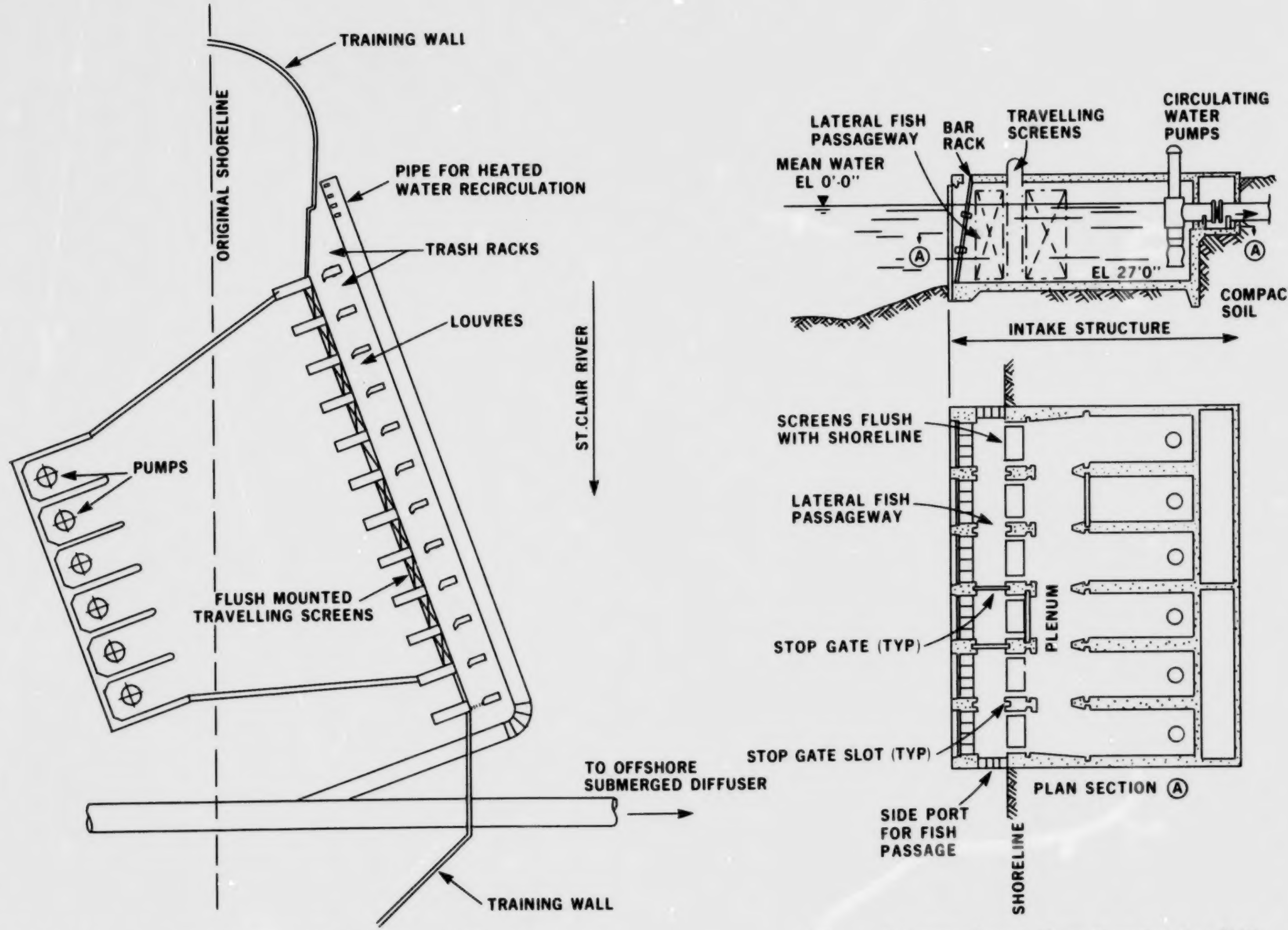
entrapment and improve their environmental acceptability. In general, intakes with a long unscreened approach channel delivering cooling water to a pump well where a screening device is placed without any fish bypass are undesirable. Fish will tend to congregate in the low velocity approach channel, and eventually either be impinged on the intake screens or pass through the screens into the cooling water pumps and condenser. As with recessed intake layouts, any structural protrusions into the lake or stream such as intake sidewalls, bulkheads, berms or piling arrays will tend to create low velocity areas or localized eddy currents where fish are likely to congregate or be trapped.

When structural protrusions and shoreline recessions are minimized, fish have a much greater opportunity to swim or be swept past the face of the intake structure. Fish entrapment and possible subsequent impingement, or passage through the cooling system can be reduced by providing fish escape potential by a combination of their own swimming ability and the existing natural conditions. Some new shoreline intakes on rivers are being designed with the screens flush mounted or angled slightly into the flow stream to provide maximum opportunity for fish to swim or be swept by the structure (15, 42). Protruding piers are minimized and a fish passageway is provided between the trash racks and the travelling screens (Figure D.13).

***Recommendation R108*. When shoreline intakes are used, breaks in the shoreline due to structural protrusions or intrusions should be minimized, and the intake screen settings should be as flush as possible with the shoreline.**

(c) Removal and Safe Return of Entrapped and Impinged Fish. The location and design of either offshore or shoreline intakes may be such that there is a reasonable degree of confidence that significant numbers of fish will not enter the forebay and become susceptible to impingement or cooling system passage. However, where significant numbers of impingeable fish enter the intake despite these measures, facilities must be provided to ensure they are returned in a viable condition to the source water body. Without a collection and return facility, fish trapped in forebays or screenwells often have no chance to escape. This is particularly true with offshore submerged intakes where the only escape route is the intake conduit or tunnel, or where long high velocity approach channels on shoreline intakes make fish escape improbable.

The conventional way of preventing debris and fish from entering the cooling water pumps and clogging the condenser tubes is to install vertical travelling screens immediately upstream of the pumps. These screens typically have a 1 cm (3/8 inch) mesh opening, which is about half the diameter of the condenser tubes. Rotation of the screens


TRAINING WALL
ORIGINAL SHORELINE
PIPE FOR HEATED WATER RECIRCULATION
TRASH RACKS
LOUVRES
ST.CLAIR RIVER
PUMPS
FLUSH MOUNTED TRAVELLING SCREENS
TO OFFSHORE SUBMERGED DIFFUSER
TRAINING WALL
LATERAL FISH PASSAGEWAY
BAR RACK
TRAVELLING SCREENS
CIRCULATING WATER PUMPS
MEAN WATER EL 0'-0"
Ⓐ
EL 27'0"
Ⓐ
COMPACTED SOIL
INTAKE STRUCTURE
SCREENS FLUSH WITH SHORELINE
LATERAL FISH PASSAGEWAY
PLENUM
STOP GATE (TYP)
STOP GATE SLOT (TYP)
PLAN SECTION Ⓐ
SIDE PORT FOR FISH PASSAGE
SHORELINE

(a) Intake for Belle River Power Plant (42)

(b) Schematic of Shoreline Intake (43)

FIGURE D.13 SHORELINE INTAKES WITH FLUSH MOUNTED SCREENS

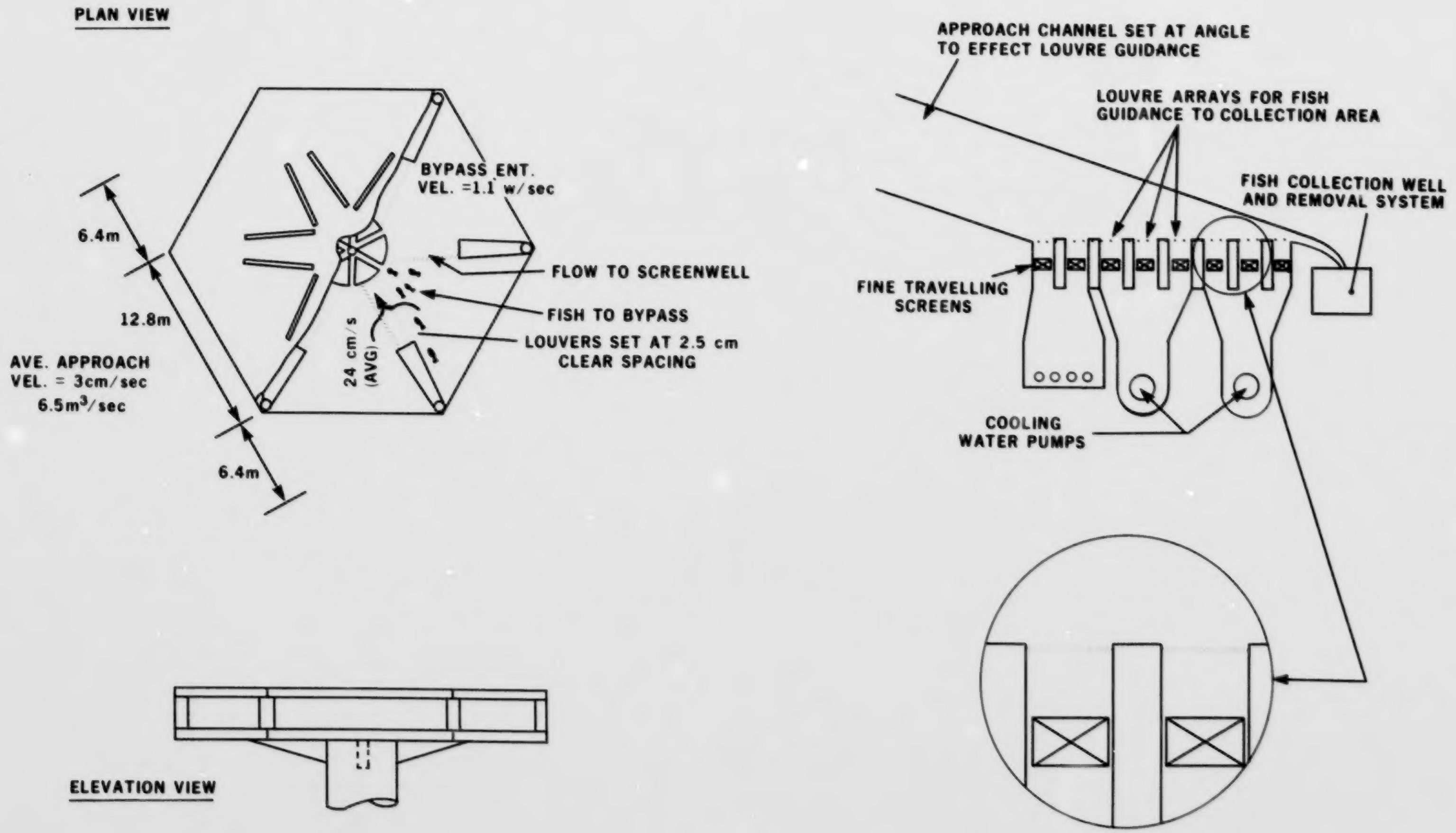
is usually triggered by the pressure difference across the screen as it becomes sufficiently blocked with debris or fish. Fish that become impinged against the screen by a combination of velocity forces and exhaustion stand little chance of survival. Mortality usually occurs from descaling and/or asphyxiation during escape attempts, removal from the water for prolonged periods when the screen rotates, or screen wash sprays applied to remove the impinged materials. In many cases, fish that are washed from the screens are collected in a trash sump and disposed of.

Numerous design options for forebays, screenwells and screens will minimize fish impingement losses (15, 27, 28, 33, 36). These include but are not limited to:

(i) louvre arrays for fish diversion and a fish return system in offshore submerged intakes;
(ii) an array of vertical louvres set at an angle to the flow approaching the screenwell to divert fish into a bypass and return system;
(iii) an array of conventional vertical travelling screens set at an angle to the flow aproaching the pumpwell to divert fish into a bypass and return system;
(iv) horizontal travelling screens set at an angle to the flow approaching the pumpwell to divert fish into a bypass and return system;
(v) modified continuous operation vertical travelling screens with fish collection buckets, low pressure screen wash and a fish collection and return system;
(vi) fine mesh screen systems for diversion and collection of larvae and other small fish;
(vii) improved forebay and screenwell designs;
(viii) various combinations of the above such as vertical or horizontal travelling screens combined with a louvre diversion system.

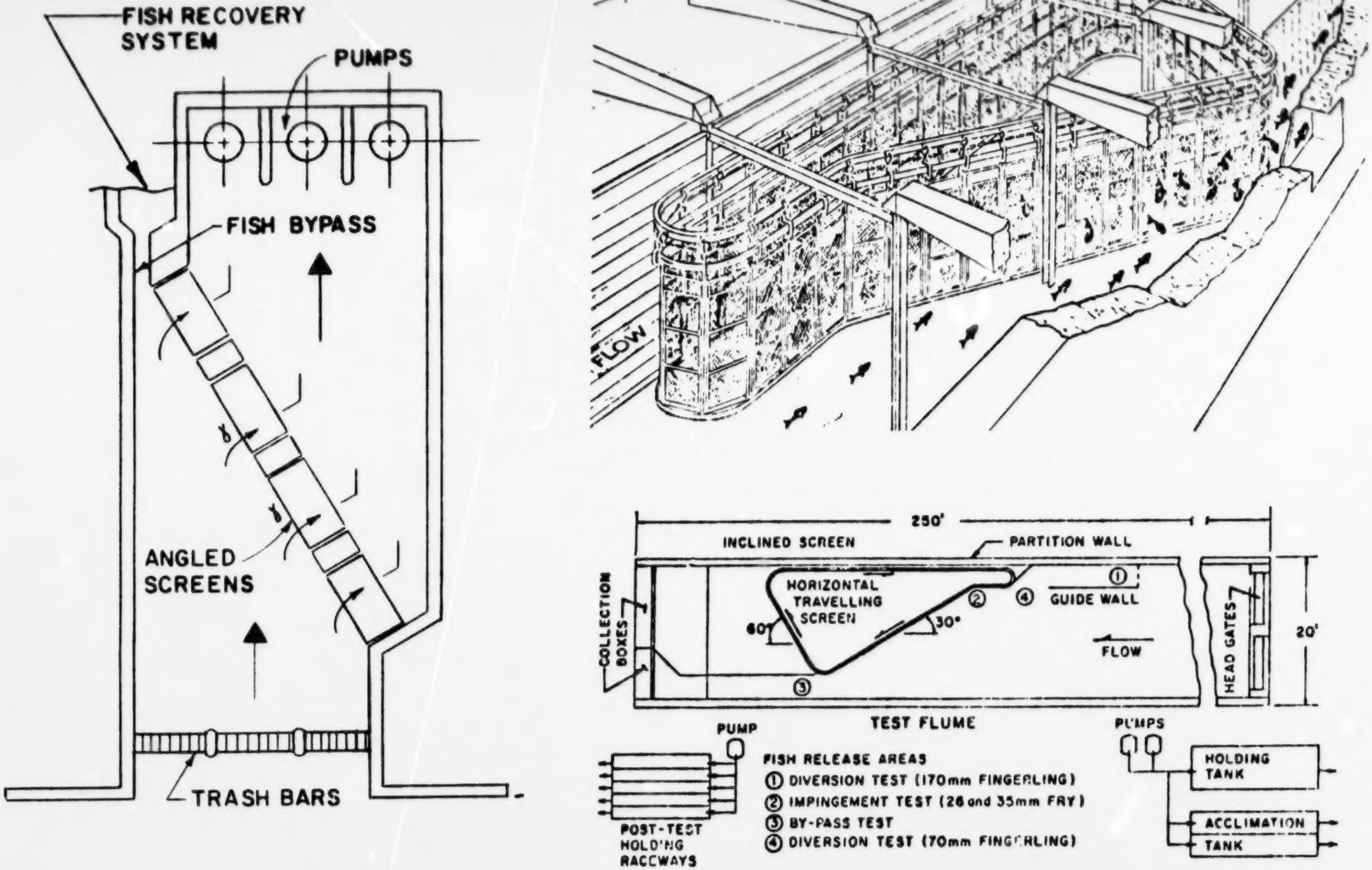
Fish respond to angled louvre systems (Figure D.14), by attempting to swim away from the vertical louvre array. This moves them back into the flow stream which carries them along the barrier until eventually they reach the bypass system at the downstream end of the array. The effectiveness of louvre diversion systems depends on the orientation of the louvre array, the spacing and angle of the vanes, the approach velocity and other factors. The most effective louvre vane spacing and array angle to the flow depend to some extent upon species, size, and ability of the fish to be diverted (27). Louvre systems have been demonstrated to be more than 95 percent effective in diverting fish in both offshore submerged intake and screenwell approach flow applications (36).

A disadvantage of a louvre system is that it does not remove trash and its function may be impaired by a heavy trash load. To overcome these disadvantages bar


PLAN VIEW
BYPASS ENT.
VEL. =1.1 w/sec
6.4m
12.8m
6.4m
AVE. APPROACH
VEL. = 3cm/sec
6.5m³/sec
24 cm/s
(AVG)
FLOW TO SCREENWELL
FISH TO BYPASS
LOUVERS SET AT 2.5 cm
CLEAR SPACING
ELEVATION VIEW
APPROACH CHANNEL SET AT ANGLE
TO EFFECT LOUVRE GUIDANCE
LOUVRE ARRAYS FOR FISH
GUIDANCE TO COLLECTION AREA
FISH COLLECTION WELL
AND REMOVAL SYSTEM
FINE TRAVELLING
SCREENS
COOLING
WATER PUMPS

(a) Louvre System at Nine Mile Point G.S. Offshore Submerged Intake (27) (b) Louvre System in Forebay at Point Lepreau G.S. (44)

FIGURE D.14 LOUVRE DIVERSION SYSTEMS FOR COOLING WATER INTAKES


FISH RECOVERY SYSTEM
PUMPS
FISH BYPASS
ANGLED SCREENS
TRASH BARS
FLOW
250'
20'
INCLINED SCREEN
PARTITION WALL
HORIZONTAL TRAVELLING SCREEN
60°
30°
① GUIDE WALL
②
③
④
FLOW
COLLECTION BOXES
HEAD GATES
TEST FLUME
PUMP
PUMPS
HOLDING TANK
ACCLIMATION TANK
POST-TEST HOLDING RACEWAYS
FISH RELEASE AREAS
① DIVERSION TEST (170mm FINGERLING)
② IMPINGEMENT TEST (26 and 35mm FRY)
③ BY-PASS TEST
④ DIVERSION TEST (70mm FINGERLING)

(a) Schematic of Conventional Vertically Travelling Screens (45)

(b) Horizontal Travelling Screen Test Facility (33)

FIGURE D.15 FISH DIVERSION BY SCREENS SET AT AN ANGLE TO THE APPROACHING FLOW

racks may be installed ahead of the louvres or the louvres themselves may rotate in a manner similar to that of the travelling screens (15). Conventional travelling screens could also be used downstream of the louvres to remove smaller debris.

Conventional vertical travelling screens (Figure D.15a) set at an angle to the approaching flow generally have two advantages over angled louvres (43):

(i) backup screens, which are required behind louvre systems to remove fine debris and nondiverted fish, are not necessary; and

(ii) screens operate efficiently at a higher approach to bypass velocity ratio (1:1 instead of 1:1.5) thereby reducing bypass flows and pumping costs.

They will usually also have greater diversion efficiencies since they are capable of diverting a higher percentage of smaller fish. Even sluggish or disoriented fish, which could pass through a louvre array, tend to move along the face of angle screens into a bypass.

Horizontal travelling screens (Figure D.15b) may be one of the more promising concepts for protection of fish eggs and larave (27). The face of a horizontal screen angled across the approaching flow stream moves fairly rapidly (0.4 to 1.2 m/s) in the downstream direction guiding fish to a bypass facility at the downstream end. A number of prototype horizontal travelling screens have shown high diversion efficiencies and survival rates for both large and small fish of different species. The size of the fish that can be effectively screened depends on the angle of the screen to the approaching flow and the screen mesh size (15, 27). Although these screens are promising and are included in various configurations in proposed new screening design concepts, there is not yet any power plant scale operating experience. Costs and maintenance problems may be significant deterrents to their use in the near future.

Modifying conventional vertical travelling screens to improve their capability to safely remove, collect and return fish offers advantages for use at future stations since the basic screen is a proven, off-the-shelf design. Improved environmental designs include continuous rotation to reduce the time fish remain impinged, fish buckets or baskets to ensure fish are effectively lifted out of the water for conveyance to the collection facility, lower pressure screen wash sprays to reduce descaling, and a fish collection trough and return facility. Some of these features are illustrated in Figure D.16. Full scale operating experience has demonstrated greater than 90 percent average immediate survival for a wide range of freshwater and marine species, and more than 80 percent survival for some more sensitive species (27).

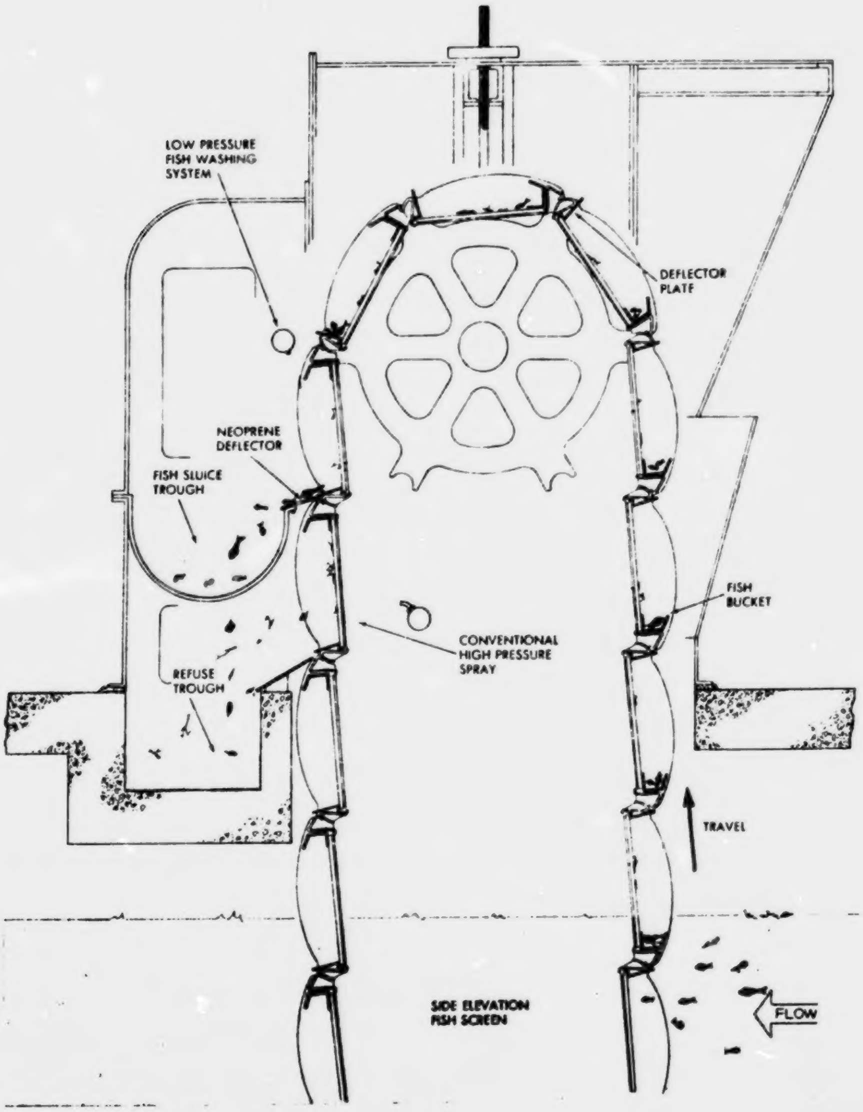

LOW PRESSURE FISH WASHING SYSTEM
DEFLECTOR PLATE
NEOPRENE DEFLECTOR
FISH SLUICE TROUGH
FISH BUCKET
CONVENTIONAL HIGH PRESSURE SPRAY
REFUSE TROUGH
TRAVEL
SIDE ELEVATION FISH SCREEN
FLOW

FIGURE D.16 VERTICAL TRAVELLING SCREEN MODIFIED TO MAXIMIZE FISH RECOVERY (45)

The effectiveness of any screening device in diverting very small fish, including fish eggs and larvae, depends on the mesh size of the screen. A considerable amount of experimentation is underway with fine mesh screens (15, 27, 39, 43, 46). Mesh sizes being considered range from the conventional travelling screen size of 1 cm down to about 0.5 mm. Figure D.17 shows two empirically derived relationships for the length of fish that will pass through a given size mesh opening (15). Test results have indicated, for instance, that 100 percent of striped bass larvae 4.5 to 5.0 mm long will be retained on a mesh having a 0.5 mm clear opening. A screen with a 1 mm clear opening would retain only 20 to 35 percent of this size fish (27). Data are also available for other species including small mouth bass, large mouth bass and chinook salmon. A number of current investigations are being directed at survival of larvae impinged on fine mesh screens, fouling and clogging of the screens, hydraulic performance and maintenance requirements (39, 43, 46, 47, 48, 49, 50). Studies at a full scale test facility indicate that fish larvae as small as 10 mm can be effectively guided along an angled, fine mesh screen given the proper mesh size and velocity conditions (51). These and other experiments indicate that improved protection against entrainment of fish eggs and larvae can be achieved with an appropriate combination of screen mesh size and screen design. Manufacturer's data indicate that the hydraulic efficiency of a 2 m wide travelling screen reduces about 22-28 percent when the mesh size is reduced from 1 cm to 0.3 cm (15). Although the practicability of operating screens with very small mesh sizes may be questionable, the use of mesh sizes smaller than the conventional 1 cm appears feasible.

New intake designs are likely to incorporate an appropriate combination of the design features discussed above. For instance, louvre arrays may be combined with flush mounted fine mesh vertical or horizontal travelling screens. Examples of some new design concepts for shoreline intakes are illustrated in Figure D.18 (52).

An integral part of a fish bypass system is an effective fish recovery and return system. Fish pumps, elevators, lift nets, troughs and sluices, and piping have proven effective for collecting and returning live fish to their original body of water (15, 27). A number of these facilities are being incorporated into the intake designs for Canadian generating stations (28, 53). An air lift system (Figure D.19) indicates considerable promise as a practical, low maintenance and low stress method of dealing with fish removal from bypass facilities (54).

The foregoing discussion indicates that intake designs are available to effectively divert, collect and return fish that have become entrapped in the intake flow stream. There may still be instances where the number of fish entering the intake

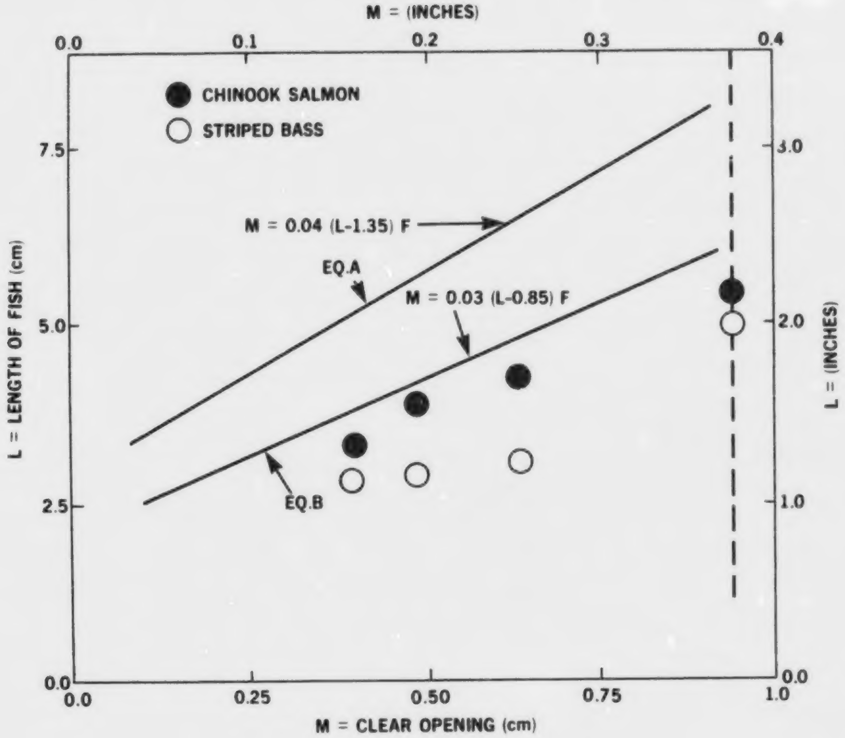
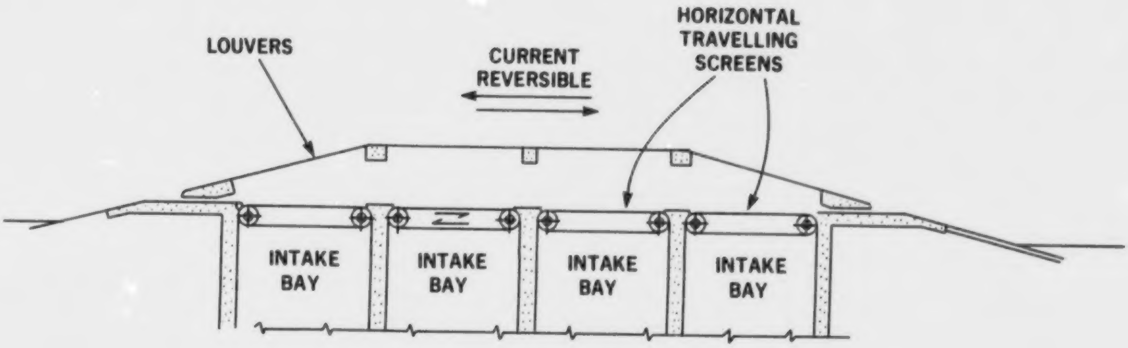
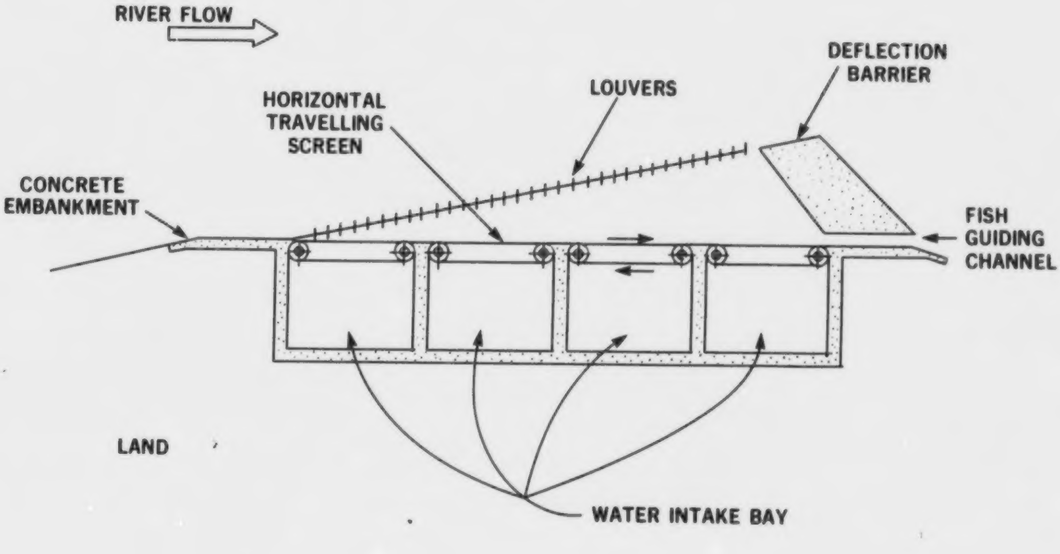


FIGURE D.17 SCREEN MESH SIZE VS LENGTH OF FISH SCREENED (15)

flowstream is expected to be low and may not warrant initial installation of an elaborate bypass and return system. In such instances, provision should be made for retrofitting a fish bypass and return system should the need arise. Where a fish bypass system is not installed initially and there is an opportunity for fish to make their way back to the source water body (i.e., surface intake), design criteria should be used that will reduce the probability of impingement. These include uniform flow patterns, low approach velocities through forebays and screenwells, and avoidance of areas that will trap fish. Approach velocities should be maintained below the sustaining swimming speeds of the species and sizes of fish expected to be entrapped. For many species, the sustaining speeds are only about 15 cm/s in water to which they have been thermally adjusted (15, 33). If the flow approaching the screens is not uniform, there may be high velocity areas through portions of the screen. Similarly, if a skimmer or curtain wall in front of the screens causes downward flow in front of the wall and high velocity flow beneath it, fish will be more easily drawn into the space between the wall and the screens, and have no opportunity to


LOUVERS
CURRENT REVERSIBLE
HORIZONTAL TRAVELLING SCREENS
INTAKE BAY
INTAKE BAY
INTAKE BAY
INTAKE BAY

(a) Multifarious power plant intake structure (MWIS) for a Lake, Estuary or Ocean Site


RIVER FLOW
DEFLECTION BARRIER
LOUVERS
HORIZONTAL TRAVELLING SCREEN
CONCRETE EMBANKMENT
FISH GUIDING CHANNEL
LAND
WATER INTAKE BAY

(b) Modification of MWIS for operation on rivers

FIGURE D.18 NEW DESIGN CONCEPTS FOR SHORELINE INTAKES (52)

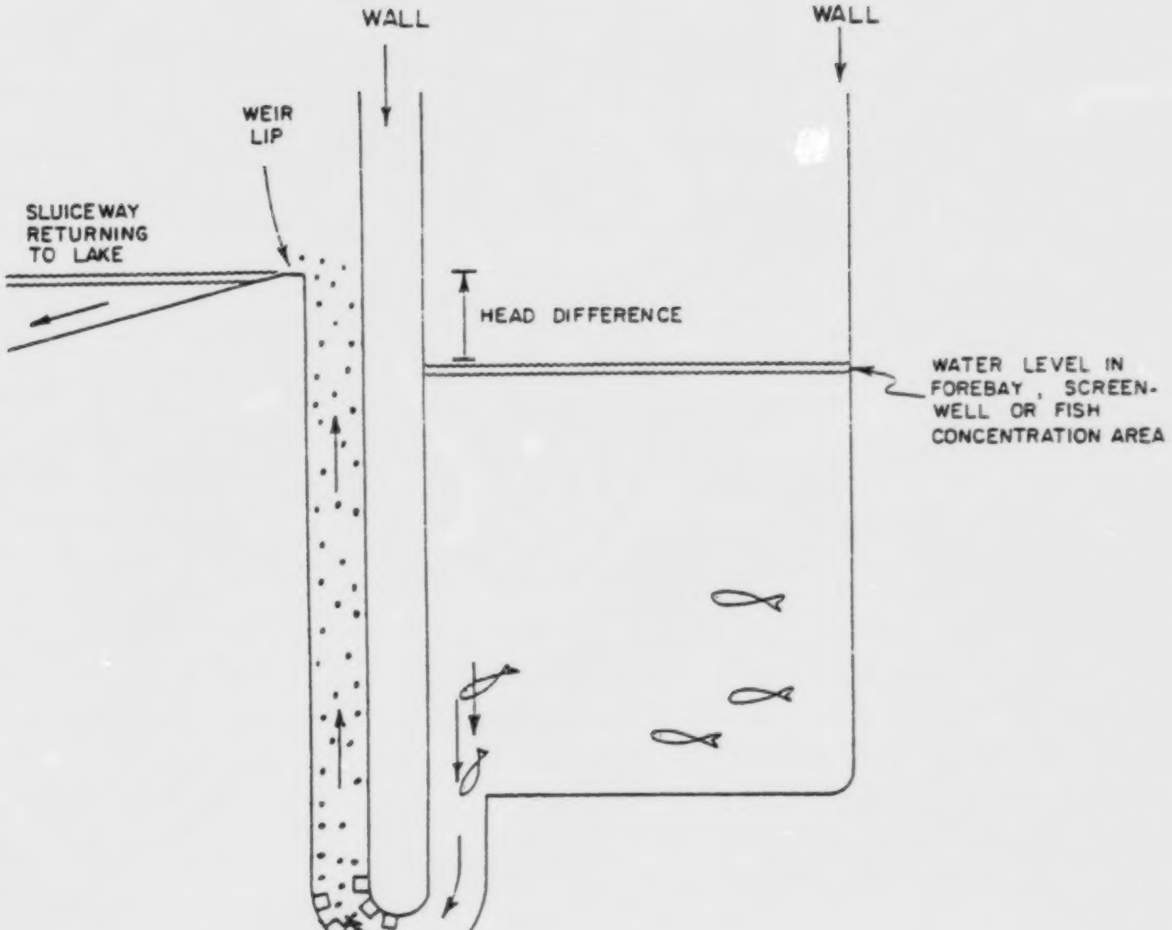

WALL
WALL
WEIR LIP
SLUICEWAY RETURNING TO LAKE
HEAD DIFFERENCE
WATER LEVEL IN FOREBAY, SCREEN-WELL OR FISH CONCENTRATION AREA
AIR INJECTION PORTS

FIGURE D.19 AIR LIFT SYSTEM FOR FISH REMOVAL (54)

escape. An improved design for the Dalhousie G.S. intake skimmer walls developed to minimize fish entrapment potential is shown in Figure D.20.

In summary, numerous design options are available to improve the environmental performance of cooling water intakes. These are becoming advanced to the stage where impingement and/or passage through the cooling system of even the smaller life stages of fish can be subtantially reduced. Based on these considerations the following control measures are recommended:

Recommendation R109. ***Intakes for once-through cooling systems should be designed with the following features.***

(i) ***All intakes should be equipped with an effective fish bypass and return system unless it is demonstrated that there is a low probability of significant numbers of fish being entrained in the intake flow stream.***

(ii) ***All intakes where a fish bypass system is not installed during initial construction due to a demonstrated low probability of significant fish impingement should have:***

- ***(a)*** ***a uniform flow velocity not greater than 15 cm/s approaching the screens,***
- ***(b)*** ***no areas of vertical flow in the forebay or screenwells,***
- ***(c)*** ***provision for retrofitting a diversion and bypass system at a later date.***

D.5 Minimization of Damage to Organisms Entrained

D.5.1 General

Although the intake recommendations will substantially reduce entrapment and perhaps entrainment, situations are still likely to occur at some new generating stations where a considerable number of smaller fish are entrained and exposed to the stresses of cooling system passage.

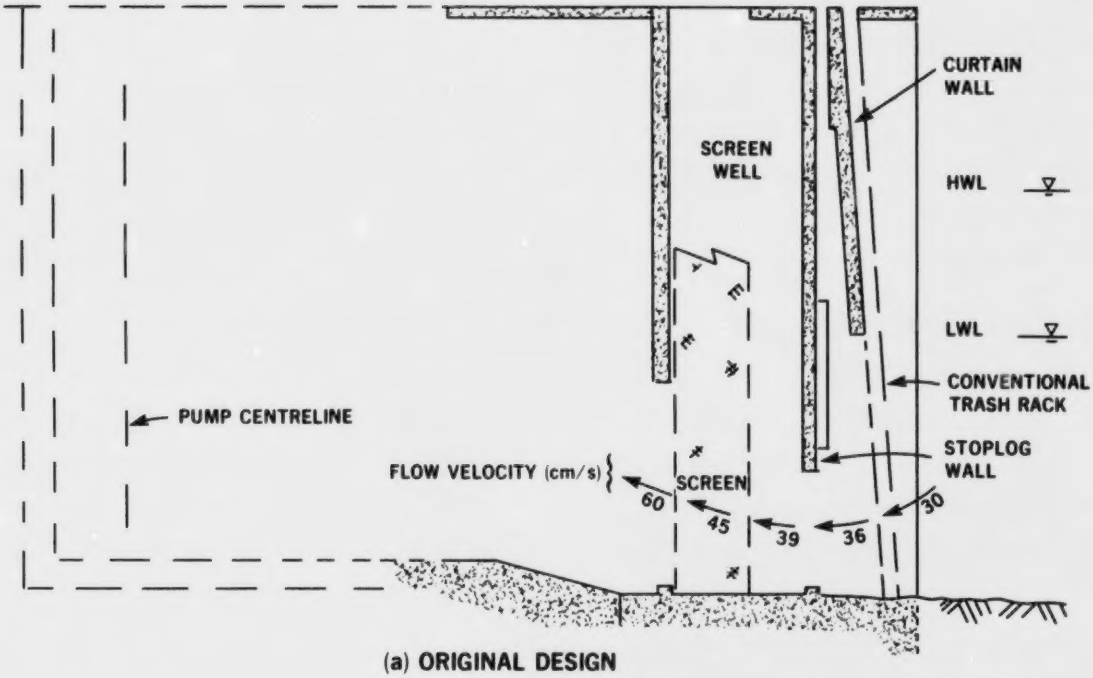
The cause of damage to aquatic organisms passing through once through cooling systems can be divided into three categories (3):

a) lethal temperatures or lethal temperature rises,

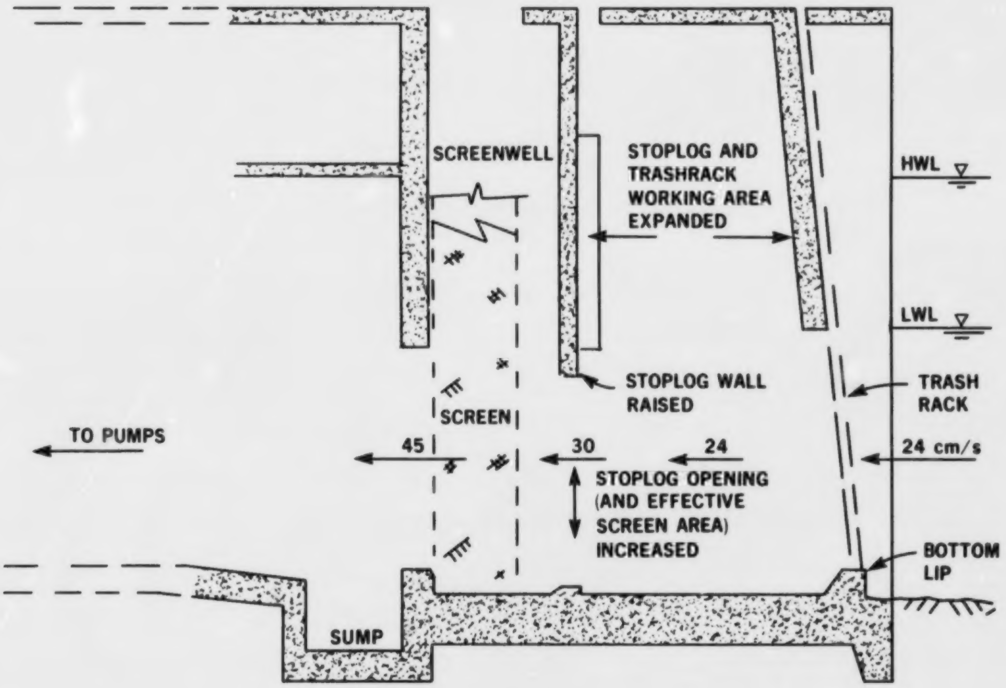
b) physical stresses (shear and acceleration forces, abrasion, pressure change, etc.), and

c) exposure to chemicals (biocides, corrosion and scale control).

Since both impingement and entrainment losses are volume related, cooling systems should be operated to minimize water intake. However, if temperature rise and


CURTAIN WALL
SCREEN WELL
HWL
LWL
CONVENTIONAL TRASH RACK
PUMP CENTRELINE
STOPLOG WALL
FLOW VELOCITY (cm/s)
SCREEN
60
45
39
36
30

(a) ORIGINAL DESIGN


SCREENWELL
STOPLOG AND TRASHRACK WORKING AREA EXPANDED
HWL
LWL
STOPLOG WALL RAISED
TRASH RACK
SCREEN
TO PUMPS
45
30
24
24 cm/s
STOPLOG OPENING (AND EFFECTIVE SCREEN AREA) INCREASED
BOTTOM LIP
SUMP

(b) IMPROVED DESIGN

FIGURE D.20 IMPROVED SCREENWELL DESIGN (DALHOUSIE GENERATING STATION) (36)

maximum discharge temperature are to be maintained below levels that will cause mortality to entrained fish eggs and larvae, a limit is imposed on the reduction in cooling water volume that can be achieved. The desirability of a temperature limitation depends on the amount of chemically and mechanically induced mortality that would occur with non-lethal temperatures. If this is high, a temperature limit will not reduce the total entrainment loss and, in fact, is likely to increase total loss by requiring a higher intake volume. On the other hand, if chemical additions are infrequent and mechanical factors do not cause mortality of most entrained ichthyoplankton, it is inappropriate to allow temperatures that exceed the upper lethal threshold of entrained species.

Because the need for temperature protection depends on the extent of physical and chemical damage, protection against physical and chemical stresses is discussed first, followed by discussion of temperature.

D.5.2 Protection from Physical Damage

A physical factor such as shear stress is considered to be a "deleterious substance" under the Federal Fisheries Act (55), with status equivalent to heat or chemicals. A deleterious substance is defined in Section 33 of the act as including water "that has been treated, processed or changed, by heat or other means....so that it is rendered or is likely to be rendered deleterious to fish....". Fish are defined as "shellfish, crustaceans, marine animals and their eggs spawn, spat and juvenile states" and hence include those smaller life stages that are susceptible to passage through cooling water intake screens.

Entrained fish are subjected to several types of physical stress in passage through the cooling system. In-plant physical stresses arise from (3):

- contact with fixed or moving equipment, such as screens, pumps and piping,
- pressure changes, especially the negative pressure within pumps,
- shear forces in areas of extreme turbulence or boundary proximity,
- accelerative forces resulting from changes in velocity and direction
- buffeting and collision with the particles passing along with the organisms (damage depending on load density and size), and
- cavitation in regimes of partial vacuum.

Research reports and papers (e.g., 7, 56, 57, 58, 59) indicate that mortality of ichthyoplankton from physical stress varies from 0 to 100 percent of the total numbers entrained. The experimental and operational results obtained to date are insufficient to make any firm generalization on the rate of mechanically induced mortality in every situation.

Available experimental evidence points to pumps as the major source of physical damage inflicted on entrained organisms (3, 60). The pumps create a rapid pressure drop approaching the impeller, immediately followed by a pressure increase on the back side of the impeller. The highest acceleration forces in the cooling system occur in the cooling water pumps. Acceleration forces resulting from turbulent eddies are of such magnitude, usually several times that of gravity, as to possibly cause immediate or latent damage to entrained fish larvae. The highest acceleration forces normally result from impact with solid surfaces and are usually immediately lethal. It appears that even intermediate acceleration forces are potentially lethal to fragile ichthyoplankton.

Generally, large (5 to 50 mm) clupeid and atherinid fish larvae are most susceptible to physical damage. Relatively higher percentages of smaller organisms will survive passage through the cooling system (3).

The shear stresses developed in the pumps are caused by spatial differences in velocity in the moving fluid, such as the edge of eddies in a turbulent flow regime or where water flows across a solid surface. Estimates of the shear stresses developed in pumps indicate that these will be the highest shear stresses encountered by an organism in passing through the cooling system (3). Shear stresses have been compared with experimental data on fish tolerance to shear stress in estimating entrainment mortality at power plants. At the Calvert Cliffs nuclear plant, for instance, it was estimated that shear stress alone would be enough to cause 100 percent mortality of entrained eggs and larvae (3).

A lower rate of mortality could be expected if the shear stress in the pump selected was below the threshold or tolerance shear stress of the fish entrained. Evidence is not yet sufficient to indicate which charcteristics of pump design offer the greatest potential for reduction in physical stresses within the water flow stream. Investigations are under way to determine the effect of factors such as size, type, impeller design, RPM and tip speed. Despite the need for more supporting evidence, designers should be encouraged to investigate physical stress characteristics in selecting pumps for new stations. Hence the following is recommended:

Recommendation R110. Opportunities to minimize physical stresses to entrained aquatic organisms should be considered in selecting cooling water pumps.

D.5.3 Protection from Chemical Damage

In addition to being subjected to a variety of physical stresses, entrained fish will also be exposed to any chemicals that are added to control biofouling, corrosion, scaling or silting in the main condenser or auxiliary cooling water systems. These chemicals may also cause concern in the receiving waters if release concentrations are high enough to cause damage to fish and other aquatic organisms residing in the thermal plume, or to foster synergistic reactions with other chemicals.

(a) Biofouling Control. The cooling water circuits in steam-electric plants may be prone to biofouling due to organic buildup on their surfaces. The optimum temperature for biofilm growth is reported to be around 35°C, which is in the range of tube wall temperatures found in power plant steam condensers (61). Biofouling on condenser tubes consists of an insulating layer of slime-forming organisms which form on the waterside of the tubes. This biofilm is generally contaminated with deposits of silt, and corrosion and scale products. It reduces heat transfer and provides sites for under-deposit corrosion (61). Figure D.21 shows a simplified diagram of the biofouling process.

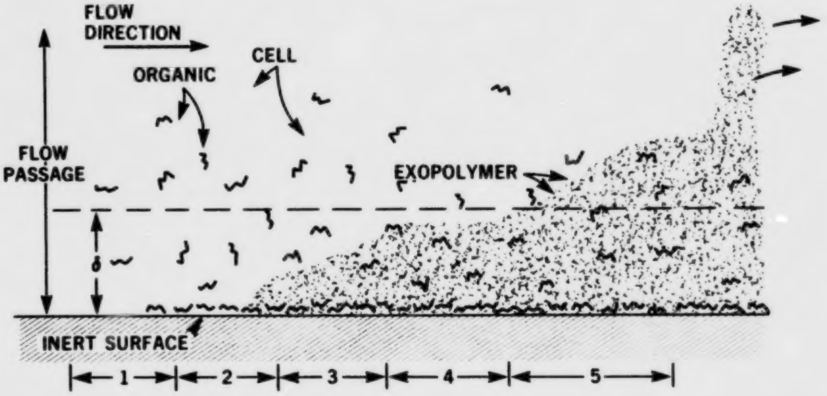


FIGURE D.21 SIMPLIFIED BIOFOULING PROCESS (61)

If sufficient nutrients are present, the film will grow in thickness to a steady state. At steady state, film thicknesses of up to 500 micrometers have been reported for water moving at 1.8 m/s.

Slime forming organisms in freshwater include fungi, bacteria, iron bacteria and sulphur bacteria (62). Algae, most of which are sun loving organisms, are important only in cooling towers, since they won't grow in dark places such as closed pipelines and heat exchangers (63).

The marine organisms that can cause biofouling are of two types, hard shelled, and soft shelled. The hard shelled organisms include mussels and barnacles. The soft shelled organisms include bryozoa and sponges (63). Marine organisms such as mussels and barnacles may also adhere to intake tunnel walls and piping.

Plants that experience significant condenser biofouling usually find it necessary to employ biofouling control measures such as chlorination or the use of other chemicals, or frequent mechanical cleaning of condenser tubes, either manually or using an automatic system. Some plants, however, do not have significant biofouling problems. If the intake water has certain characteristics such as high suspended solids concentration or low temperature, biofouling may not be a problem with once-through systems (62).

Chlorination of once-through cooling water has been found to effectively control biofouling in condensers. Two types of chlorine systems are used -chlorine gas and sodium hypochlorite, with chlorine gas being the more common. In the gas system the chlorine is usually stored as a liquid on-site. The liquid is passed through an evaporator which converts it to a gas which is then metered through the chlorinator, dissolved in a water stream, and injected into the cooling water flow through a diffuser.

When chlorine dissolves in water, hypochlorous acid and hydrochloric acid are formed. Hypochlorous acid (HOCl) partially dissociates into the hypochlorite ion (OCL^-) and the hydrogen ion (H^+). The concentration of HOCl and OCl^- is termed free available chlorine. Even though hypochlorous acid is superior to hypochlorite ion as a biocide, they are both powerful oxidizing agents.

Hypochlorous acid will also react with ammonia and other organic materials in water to form chloramines and various other chlorinated reaction products which are weak biocides. The chlorine contained in these compounds is called the combined chlorine residual. The total residual chlorine (TRC) concentration is the sum of the free available chlorine residual (FAC) and the combined chlorine residual concentrations. The TRC concentration is a measure of the total biocidal power.

Figure D.22a shows the formation of the various chlorine species as a function of the amount of hypochlorous acid added. In most applications, enough hypochlorous acid is added to ensure that the break point has occurred in order to take advantage of the biocidal power of HOCl.

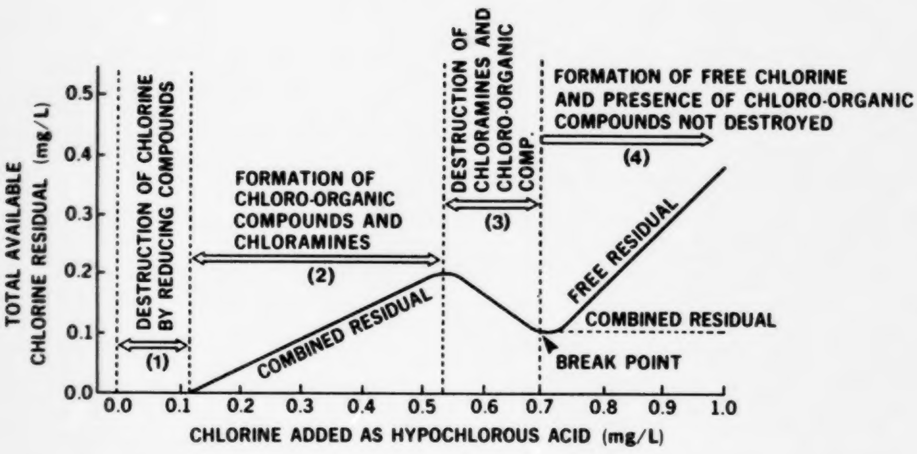
At any given site the amount of chlorine residual required at the condenser outlet to ensure adequate biofouling control depends upon the characteristics of the particular cooling water such as temperature, chlorine demand, suspended solids concentrations and quantities of nutrients present. As a general rule, 0.1 to 0.5 mg/L

FAC has been the acceptable operating range for most plants (24, 64, 65, 66, 67). However, TRC, not just FAC, has been shown to be toxic to aquatic life (62).

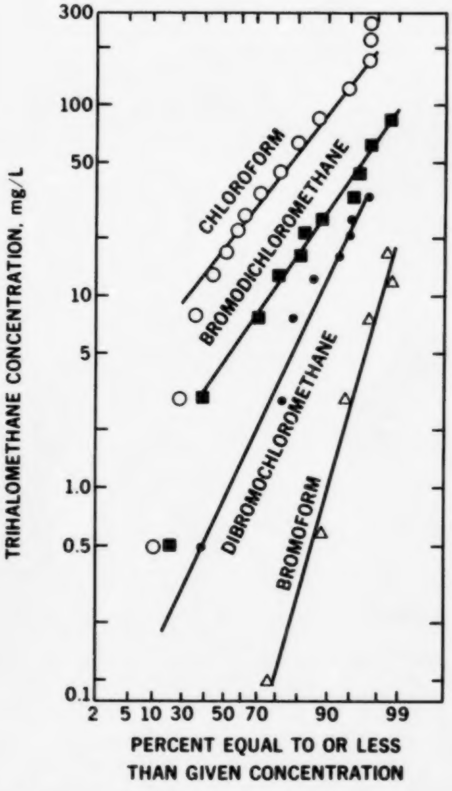
Unfortunately, the properties of chlorine that make it an effective biocide are precisely those that cause environmental damage. In general, two main categories of chlorine-containing compounds may be found in water (68) as a result of aqueous chlorination: (i) residual chlorine, chlorine compounds which possess an oxidative capacity, and (ii) organochlorine compounds formed by the reaction of oxidative chlorine compounds and organic compounds. The toxicity of residual chlorine to aquatic organisms has been well documented (e.g., 68, 69, 70, 71, 72, 73, 74, 75, 76). In addition, a great deal of research has been conducted into the formation of organochlorines in fresh water (62, 68, 77). In one study over 50 organochlorine compounds were found in ppb concentrations in chlorinated samples of Watts Bar Lake water and Mississippi River water in the U.S. (62). Figure D.22b shows the frequency of occurrence of various trihalomethanes (THM) in raw and finished drinking water in the U.S. Chlorinated phenols and benzoic acids, chlorinated methylbutane derivatives and chlorinated polynuclear aromatics have also been reported in chlorinated water (78).

Where chlorine must be used for biofouling control, the amount should be the minimum demonstrated to be necessary. On-line chlorine analyzers will help ensure chlorine is not applied at levels higher than those needed, and are recommended for use at new and expanded stations. The use of an on-line chlorine analyzer for chlorine feed control is illustrated schematically in Figure D.23 (79). With such a system, the chlorine level in the discharge is monitored continuously during the chlorine application period. A feed back system controls the rate of chlorine application upstream of the condenser such that the level in the discharge does not exceed a certain concentration, say 0.5 mg/L TRC.

Where minimization of chlorine usage is being practised but the TRC in the effluent is still unacceptably high, dechlorination may be an attractive option. Dechlorination has been used effectively at water and wastewater treatment plants since 1926 (62). A number of U.S. steam electric plants currently dechlorinate (62, 77). The cost of a dechlorination system is about the same as the cost of a chlorinating system (62, 77). The most common form of dechlorination, and particularly suited for large scale operation, is injection of sulphur dioxide (62, 80). Several sodium salts of sulphur can be used in dechlorination, such as sodium sulphite ($Na_2S_2O_3$), generically known as "dry chemicals". Tests conducted by the U.S. EPA indicate that unsophisticated "make shift" dechlorination systems using "dry chemicals" can effectively limit the discharge of TRC to 0.14 mg/L or lower with 99 percent reliability (62).



(a) EFFECT OF IMPURITIES IN WATER ON TOTAL AVAILABLE CHLORINE RESIDUAL



(b) FREQUENCY DISTRIBUTION OF HALOGENATED ORGANICS IN RAW AND FINISHED DRINKING WATER IN THE UNITED STATES

FIGURE D.22 CHLORINE REACTIONS AND OCCURRENCE OF CHLORINE COMPOUNDS IN WATER (62)

Several chlorine application methods and procedures can also minimize the amount of chlorine required and its adverse affect when discharged. The chemical reactions which contribute to chlorine demand in all waters used for once-through cooling will result in a decrease in free residual chlorine as the water passes through the system. Application of chlorine at the condenser inlet instead of farther upstream at the condenser cooling water pump will allow the use of less chlorine to attain a given free residual in the condenser tubes, reducing chlorine use and environmental damage to entrained organisms in the cooling water. In salt water systems, however, or in highly eutrophic fresh water systems, it may be necessary to apply chlorine farther upstream, such as at the cooling water pump suction, in order to control biofouling in the inlet pipe. Chlorine should not be introduced upstream of the travelling screens because of possible toxicity to fish in the screenwell and the availability of mechanical means to clean the screens.

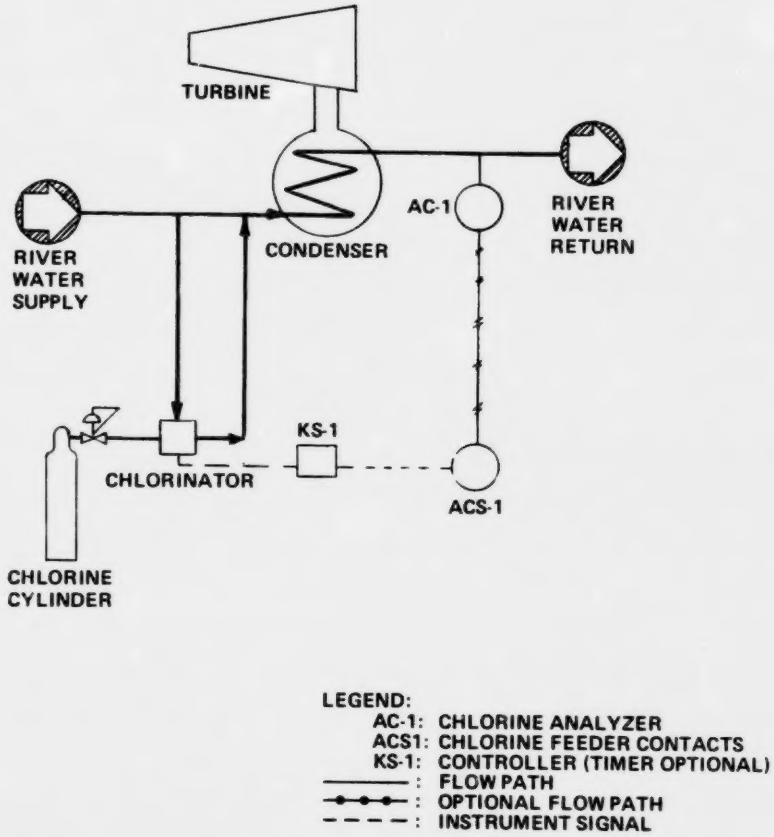

TURBINE
CONDENSER
AC-1
RIVER WATER RETURN
RIVER WATER SUPPLY
KS-1
CHLORINATOR
ACS-1
CHLORINE CYLINDER
LEGEND:
AC-1: CHLORINE ANALYZER
ACS1: CHLORINE FEEDER CONTACTS
KS-1: CONTROLLER (TIMER OPTIONAL)
——— : FLOW PATH
—●—●— : OPTIONAL FLOW PATH
– – – – : INSTRUMENT SIGNAL

FIGURE D.23 CHLORINE FEED CONTROL FOR A ONCE-THROUGH CONDENSER COOLING SYSTEM (79)

Where chlorine is used at Canadian generating stations satisfactory biofouling control has been achieved by intermittent chlorination. This practice establishes effective concentrations of chlorine in the condenser while limiting overall chlorine use. In salt water systems low level continuous chlorination may be necessary to keep intake and discharge pipes free of hard shelled organisms, particularly when the water temperature rises about 4°C (63).

In multi-unit stations, units can be subjected one at a time to intermittent chlorination so that some unchlorinated cooling water is available to dilute and/or react with the chlorine residual. Chlorination can be undertaken during daylight hours to facilitate the reduction of the free available chlorine (FAC) residual by sunlight (81, 82).

Chemical alternatives to chlorine for biofouling control can be classified as oxidizing and non-oxidizing. The oxidizing chemicals include chlorine dioxide, bromine, ozone, bromine chloride, formic acid and iodine. Of these, bromine chloride, chlorine dioxide, ozone and formic acid are appropriate for large scale application (62, 83). Although chlorine residuals are not present when using these chemicals, other residuals which are also toxic will be present.

Since oxidizing biocides will react with a wide variety of contaminants in water, their decay to non-toxic compounds is relatively rapid (62). Non-oxidizing biocides, however, react very selectively with microorganisms and other life forms and can therefore pose a substantial environmental hazard (62). Non-oxidizing biocides include acrolein, arsenates and arsenites, ammonia and amines, cyano compounds, metals (salts), organometals, phenols -chlorinated and phenylated, and various proprietary formulations.

Other chemical biofouling control methods (80, 84) include the condenser biocide soak and antifouling coatings. The biocide soak is accomplished by shutting down and flooding the condenser with a biocide. After the slime is killed, the biocide is pumped back to storage and the condenser put back on line. Antifouling coatings and paints consist of various organometallic compounds (copper, oxides, pesticides, etc.) incorporated into vinyl-chlorinated rubber, coal-tar epoxy and other types of paint bases. The mode of action is a slow release into the water of the biocide, and may be effective for several years.

Alternative non-chemical biofouling control techniques (57, 80, 84) are attractive from an environmental point of view. The most obvious of these is manual cleaning of condenser tubes and other parts of the cooling water circuit such as intake tunnel walls, etc. However, this may require significant down time if biofouling is severe.

Two automated systems have been used in steam electric plants with some success: the Amertap system and the American Tube Cleaning System (ATCS, formerly American MAN system). The Amertap circulates oversized sponge rubber balls through the condenser tubes, while the ATCS uses flow driven brushes which are passed through the condenser tubes intermittently by reversing the direction of cooling water flow through the condenser.

Other non-chemical biofouling control methods have been used with some success in specific instances. An increase in the velocity of water moving through the precondenser components has been used in an estuarine cooling system (84). Velocities above 1.5 m/s seem to inhibit settling of various fouling organisms. A U.S. west-coast utility uses heated condenser cooling water to control marine fouling in the intake and discharge conduits of their coastal stations. The plants are designed so that the heated discharge water can be recvcled through the condenser to pick up additional heat and can then be discharged through either the intake or the outfall conduits.

Other non-chemical techniques that have been proposed are: (i) heat soak (condenser is drained while maintaining temperature on steam side), (ii) ultraviolet radiation, (iii) ultrasonic vibration, (iv) automatic water jet cleaning, (v) osmotic shock (using freshwater to kill marine organisms in precondenser cooling water structures), and (vi) anoxic water (shutting a system down and letting the water go anaerobic for several days).

Table D.6 shows the extent of usage of various biofouling control methods across Canada in once-through cooling systems (85). As indicated in the table, only 31% of once-through plants in Canada chlorinate. In western Canada, only one plant out of ten surveyed indicated the use of chlorine. Chlorine is used in 45% of the plants using sea water and 26% of the freshwater plants. No stations have reported using continuous chlorination for the control of mussels and other organisms in seawater cooling systems.

A large percentage of Canadian plants with once-through cooling systems do not use chlorine either because biofouling is not a problem or because other methods are used. However, where biofouling control is required, chlorine is the most common biocide. It is expected that this trend will continue over the next several years until other biocides have been demonstrated to be competitive on an economic and environmental basis.

As a result of chlorine minimization programs some plants in Canada are currently operating below 0.5 mg/L TRC measured at the condenser outlet (86). Tests are also being conducted with on-line TRC analyzers in conjunction with feedback - proportional control systems to improve the control of TRC residuals.

TABLE D.6 BIOFOULING CONTROL PRACTICES FOR ONCE-THROUGH COOLING SYSTEMS AT CANADIAN STEAM ELECTRIC PLANTS (85)

	Number and percentage of plants that use:										Plants Surveyed	
	No Chemicals		Chlorine		Other Chemicals		Mechanical means Manual		Automatic			
Category	No.	%	No.	%	No.	%	No.	%	No.	%	Number	% of Total Operating
West	9	90%	1	10%	0	0%	4	40%	0	0%	10	100%
Central	8	53%	7	47%	0	0%	10	67%	1	7%	15	100%
East	11	65%	5	29%	1	6%	10	59%	1	6%	17	100%
Canada	28	67%	13	31%	1	2%	24	57%	2	5%	42	100%
Freshwater	23	74%	8	26%	0	0%	18	58%	1	3%	31	100%
Seawater	5	45%	5	45%	1	10%	6	55%	1	10%	11	100%

In summary, non-chemical means of biofouling control offer the least environmental risk. The most common of these are manual or automated mechanical cleaning systems. However, these may not always be effective or they may require excessive down time. Where mechanical cleaning is not effective or feasible, chlorine is expected to remain the most common biocide.

As stated previously, some existing Canadian stations using chlorine for biofouling are operating with TRC at the condenser outlet below 0.5 mg/L. At the majority of stations, it is expected that this level can be practically achieved through chlorine minimization alone. In some exceptional cases, dechlorination may be required to reach a 0.5 mg/L limit. Dechlorination has been shown to be effective in controlling TRC to less than 0.14 mg/L at some U.S. generating stations (62).

In view of the above, a recommendation to limit the concentration of TRC to 0.5 mg/L TRC at the condenser outlet would seem to be appropriate. In the case of a one- or two-unit station, this is not as stringent as the proposed U.S. EPA regulation of a maximum of 0.14 mg/L TRC at the cooling water discharge (62). A limit applied to the condenser outlet does not discriminate against a single unit station as would a limit applied to the cooling water discharge.

Since no Canadian stations have reported using continuous chlorination (85), a TRC limit specifically applicable to this practice need not be recommended. Should continuous chlorination be used in future, consideration will be given to establishing such a limit, which would necessarily be less than the limit for intermittent chlorination.

Based on the foregoing considerations, the following measures are recommended for minimizing and controlling the use of chlorine in once-through condenser systems at steam electric stations:

Recommendation R111. ***For the purpose of controlling biofouling in once-through condenser cooling systems:***

(i) chemicals should be used only when demonstrated to be necessary;

(ii) when chlorine use has been demonstrated to be necessary:

- ***(a) only the minimum amount of chlorine demonstrated to be necessary should be used,***
- ***(b) the maximum concentration of total residual chlorine (TRC) at the outlet of the condenser undergoing chlorination should not exceed 0.5 mg/L,***
- ***(c) chlorine should be applied intermittently and the injection point should be immediately upstream of the condensers and sets of auxiliary coolers, unless***

continuous chlorination or a different injection point has been demonstrated to be necessary to control biofouling. At no time should chlorine be introduced upstream of the travelling screens, and

(d) chlorine application should be limited to no more than one condenser and set of auxiliary coolers at a time and should occur during daylight hours.

Although no specific recommendation is made concerning once-through auxiliary cooling water systems, appropriate practices and procedures should also be followed to minimize the use of chlorine to control biofouling in these systems.

(b) Corrosion, Scaling and Silting Control. Corrosion, scaling and silting if not controlled, can adversely affect the operation or the physical condition of the condenser or other parts of a once-through cooling system. The extent to which these processes can cause problems depends upon the characteristics of the cooling water and the types of materials used in the cooling system.

Corrosion is an electrochemical process that occurs when metal is immersed in water. A difference in electrical potential between different parts of the metal causes a current to pass through the metal between the anode, the region of lower potential, and the cathode, the region of higher potential. The migration of electrons from the anode to the cathode results in the oxidization of the metal at the anode and the dissolution of metal ions into the water (62).

Most metals rely on a corrosion products film to impart corrosion protection. In the case of copper alloys, which are used extensively in power plant condensers, this film is usually copper oxide (Cu_2O). Therefore, copper can go into the corrosion product film or directly into solution as an ion or a precipitate in the initial stages of condenser tube corrosion. As corrosion products form and increase in thickness, the corrosion rate decreases until steady state conditions are achieved. Water characteristics and velocity will affect corrosion rates (53, 62).

Scale can be formed in condenser tubes when cooling water containing slightly soluble calcium and magnesium salts and silica is heated during its passage through the condenser, so that the solubility levels of these constituents are exceeded. Solubility levels can also be influenced by pH. Severe scaling can drastically alter cooling system fluid flow characteristics and can result in reduced heat transfer, high pressure drop, and other undesirable effects (62, 87).

Silt can be deposited in condensers and other parts of the cooling system if the cooling water contains high concentrations of suspended solids such as small particles of clay, sand and colloidal silica (87). Silting can adversely affect the operation of cooling systems in the same manner as scaling.

Several methods can be used effectively to minimize the adverse effects of corrosion, scaling and silting. The most obvious method of corrosion control is careful selection of materials in condensers and cooling system components. For freshwater service, condenser tubes of 90/10 copper/nickel and type 304 stainless steel have demonstrated high reliability. Copper/nickel exhibits excellent corrosion resistance in fresh, salt and brackish waters. For seawater or brackish water, condenser tubes of 90/10 copper/nickel are often used and perform well. Titanium as a tube material shows promise especially in saltwater. An austenitic alloy, AL6X, reportedly offers outstanding resistance to pitting and crevice corrosion in seawater (88).

Condenser tubesheet and waterbox materials should be chosen so that they are compatible with both the circulating water and the tubes, as well as with each other. The position of the tubesheet material in the galvanic series relative to that of the tube material is very important. Cathodic protection by sacrificial anode or impressed voltage minimizes the effect of any galvanic couple, though its prime application has been to prevent inlet-end erosion and to protect the waterbox (88).

The sacrificial anode method offers an expendable metal which will corrode preferentially to the metal being protected. The impressed current method uses an electrical current applied to the metal being protected. These two methods of cathodic protection can also be used on other cooling water system components such as intake screens and valve/pipe interfaces.

Scaling and silting control in condenser tubes can be achieved by mechanical cleaning, either manually or on line. There are two main on-line condenser tube cleaning systems, the Amertap system and the American Tube Cleaning system (ATCS, formerly American MAN system). These are also used for biofouling control and are described in section D.5.3. (a).

Chemical cleaning of condenser tubes to remove scale is performed during a condenser outage. This is a relatively simple procedure using either an acid foaming technique or an acid soak. Soaking is generally regarded as the more effective method (79).

In the soak procedure the waterboxes are filled to the top rows of condenser tubes with an inhibited acid solution plus 0.5 percent ammonium bifluoride at ambient temperature. The acid strength is 5 to 7 percent. Circulation is used when practical by repumping the acid solution from the condenser to the acid delivery tank truck and then back to the condenser. The choice of acid for the soak is generally hydrochloric because of its rapid reaction with carbonate scale without forming an insoluble by-product. One Western Canadian utility, uses off-line application of acetic acid to remove scale from condenser tubes. The addition of ammonium bifluoride increases the solubility of silicate and iron deposits (72). All spent condenser cleaning solutions should be contained and should be treated prior to discharge to the environment.

Most Canadian steam electric plants do not chemically condition once-through cooling water to provide protection against corrosion, silting or scaling. However, some stations with salt water cooling add small amounts (in the order of 1 mg/L) of ferrous sulphate intermittently to the once-through cooling water to provide cooling system corrosion protection, and in particular to protect aluminum brass condenser tubes. Additions of up to 16 500 kg per year have been reported (85). Since the solubility of iron in seawater is low, it is expected most of the iron would precipitate (79). The concentration of iron in seawater is normally around 0.01 mg/L (89). Not much is known about the effects of iron on marine life although there is some concern for the effects of settled iron flocs on important commercial mussel and other shellfish resources (79). If condenser tubes were made of materials with better corrosion resistance, the addition of ferrous sulphate might not be necessary.

Some Canadian stations operating partially open cooling water systems continuously feed polyelectrolyte dispersants into the cooling water at rates from about 0.1 to 0.4 mg/L to provide silting protection to the condenser. Additions of up to 91 000 kg per year have been reported (24). Very little information is available on the chemical composition and aquatic toxicity of these dispersants. Their behaviour and effect on organisms in the aquatic biosphere in the long term is not known. Mechanical cleaning, either manual or on-line, would be a logical alternative to the use of dispersants.

In summary, a number of non-chemical methods exist for control of corrosion, scaling and silting in once-through and partially open cooling systems. These are preferred to chemical dosing of the cooling water, since there is uncertainty about the environmental effects of some of the on-line chemicals that are or could be used. The following control measures are recommended:

Recommendation R112. ***For the purpose of controlling corrosion, scaling or silting in once-through or partially open cooling systems:***

(i) ***on-line application of chemicals should not be used unless such chemicals are***

  (a) ***demonstrated to be necessary, or***

(b) demonstrated not to cause environmental damage;

(ii) if on-line application of chemicals is demonstrated to be necessary but it cannot be demonstrated that such chemicals will not cause environmental damage, the dose rates and method of application should be such that only the minimum amount of chemical necessary is used;

(iii) spent cleaning solutions generated from the off-line chemical cleaning of condensers should be contained and treated before discharge.

D.5.4 Protection from Temperature Damage

(a) General Provision. The foregoing sections indicate that in some cases at least, a high percentage of the entrained ichthyoplankton (fish eggs and larvae) that pass through the cooling system will not be destroyed by chemical exposure or physical stresses. The recommendations for use of chemicals will ensure that mortality from that cause is minimized. Relatively high percentages (more than 50 percent) of fish eggs and larvae have also been observed to survive the physical stresses of cooling system passage (e.g., 3, 4, 56, 57, 59, 60, 90, 91).

Although cooling systems should be operated at the maximum feasible temperature to minimize cooling water volume, the upper temperature tolerance of the entrained fish places a biological upper limit on the condenser discharge temperature. Unless a high rate of chemically or physically induced mortality can be demonstrated to be unavoidable in a particular situation, a temperature limit is needed to allow the entrained fish to safely pass through the cooling system and be returned in viable condition to the receiving water body.

The temperature limit will depend on the temperature tolerance of the representative important species entrained at a particular site. For the purpose of this code the representative important fish species will generally be the most temperature-sensitive of the species considered important.

The selection of important species is based on site-specific evaluation and requires extensive knowledge of the species expected to be present at the site and entrained during different seasons of the year over an extended period, general acceptance of which species are important to the ecosystem well-being, and knowledge of whether the species considered to be important will survive the physical stresses of cooling system passage.

Once the important species have been selected, the lethal temperature limits for these species can be estimated using a methodology devised by the NAS/NAE (91).

With this methodology, numerical coefficients determined experimentally for different fish species at different intervals of acclimation temperature are used in the following formulation to compute the incipient lethal temperature at different exposure times:

$$\log t = a + b\,T$$

or

$$T = (\log t - a)/b$$

where: T = incipent lethal temperature (°C)

t = exposure time (minutes)

a = intercept

b = slope

The a and b coefficients for some fish species known to occur in Canadian waters are provided in reference 91. Unfortunately, many of these are for juvenile and adult life stages of fish and can be used only as general guidance for egg and larvae tolerances. Also, since the coefficients were developed on the basis of 50 percent survival of the exposed fish, a safety factor is required to ensure full protection. Several studies have indicated that a temperature 2°C below the tolerance limit derived by the NAS/NAE formula results in no mortalities (91).

In some situations it will be difficult to define a most temperature-sensitive species because of variations in the temperature tolerances of various life stages of various species present during the year. Where this occurs, the representative important species should be selected in such a way that, with respect to temperature damage, the protection of this (or these) species ensures the protection of other important species. In addition to the variation in susceptibility of different species to temperature damage, there are numerous examples of changes in species over time which could make the selection of a representative important species for design of a power plant cooling system difficult. For example, when the sea lamprey population exploded in the Great Lakes in the 1940's, lake trout, once abundant, disappeared and whitefish and cisco populations declined sharply (92). The decline of the lake trout allowed the alewife to flourish. This led to massive stocking programs of coho and chinook salmon as coldwater predators to control the alewife population. As neither lake trout nor salmon sustain themselves today, they are maintained through continued stocking and, hence, may not present a major egg or larvae entrainment concern.

Similar situations exist in other freshwater systems, particularly in some newly created reservoirs where the fish population has not been fully established or stabilized. For instance, large mouth bass and walleye have been stocked in Cookson Reservoir, which was built as a cooling reservoir for the Poplar River generation station. Additional species could be added to the stocking program in the future years. Hence, the species that are going to be representative and important at a given site during the life of a station are not always known at the design stage.

It is useful to look at species that occur most commonly in Canadian waters, and those species which are dominant in sport and commercial fishing, to get an indication of those species which may be of frequent concern. Examination of available fish occurrence data (e.g., 93, 94, 95, 96) for some 134 species in 48 large lakes and reservoirs indicate that the 20 top ranking species by frequency of occurrence in Canadian freshwaters are those listed in Table D.7. As indicated, temperature tolerance data are available (91, 97) for 7 of the 12 most commonly occurring species. The 10 top ranking species in commercial fish catch on the Great Lakes are listed in Table D.8. Among the most popular sports fish in the Great Lakes are lake trout, coho and chinook salmon, walleye and small mouth bass. Walleye is one of the most popular freshwater sports fish nationwide and perhaps is a good indicator species when considering temperature limitations for cooling systems where definitive information on the representative important species is not available.

A further consideration is that a representative important species need not necessarily be one of the more prominent sport or commercial fish. They may well be part of the food supply for some of the more desirable species. For instance, there is concern that overharvesting of forage fish like smelt and alewives may limit supportable populations of trout and salmon on the Great Lakes (92). A further reduction of smelt or alewife populations through entrainment in power plant cooling waters would increase this concern.

A number of analyses have been carried out using the NAS/NAE formula to give general guidance on the species that can be protected by different temperature limits. The two variables in this formula are acclimation temperature and the time of exposure to an elevated temperature. Fish will normally be acclimated to the ambient water temperature of the source water body, which will typically be between 10 and 20°C during summer when fish larvae are often most abundant. Exposure time of entrained fish to maximum or near maximum temperature will be equivalent to the travel time in the discharge conveyance system (channel, tunnel or pipe) plus some additional time in the receiving waters, depending on the dispersion characteristics. Although travel times in the conveyance system may often be fairly short when all units of a multi-unit generating

TABLE D.7 MOST COMMONLY OCCURRING FISH SPECIES IN CANADIAN FRESHWATERS (93, 94, 95, 96)

Species		Frequency of Occurrence in 48 Lakes	Temperature Tolerance Data Available
1)	Northern Pike	28	X
2)	Burbot (Ling)	25	
3)	White Sucker	25	X
4)	Lake Whitefish	24	
5)	Yellow Perch	24	X
6)	Spottail Shiner	23	
7)	Trout-perch	22	
8)	Emerald Shiner	20	X
9)	Walleye	18	X
10)	Brook Stickleback	18	
11)	Lake Trout	17	X
12)	Lake Herring (Cisco)	17	X
13)	Slimy Sculpin	17	
14)	Lake Chub	16	
15)	Longnose Dace	16	
16)	Johnny Darter	16	
17)	Fathead Minnow	15	X
18)	Pearl Dace	15	
19)	Blacknose Shiner	15	
20)	Longnose Sucker	14	

station are operating (2 to 5 minutes), they increase as the number of units in operation are reduced. This occurs because all units are often on a common discharge in which reducing the cooling water flow simply reduces the velocity of flow and increases the travel time. Approximate exposure times for some existing and proposed stations with different numbers of units operating are provided in Table D.9. Multi-unit stations are frequently operated at less than full capacity during the summer months, which causes longer exposure times when high larvae concentrations normally occur. It can be seen

TABLE D.8 MOST VALUABLE COMMERCIAL FISH SPECIES ON THE GREAT LAKES (92)

Species		Harvest Value ($ 1979)	Temperature Tolerance Data Available
1)	Yellow Perch	17 943 514	X
2)	Lake Whitefish	6 870 989	
3)	Smelt	2 249 569	
4)	White Bass	1 231 475	
5)	Eel	724 319	
6)	Lake Herring (Cisco)	709 521	X
7)	Lake Trout	479 702	X
8)	Alewife	458 777	X
9)	Channel Catfish	415 617	X
10)	White Perch	337 292	

from Table D.9 that exposure times in excess of 10 minutes may readily occur at reduced capacity factors and, in fact, occur at some stations when operating at full capacity.

Figures D.24 and D.25 show upper temperature tolerances computed for Canadian fish species for which temperature tolerance data are available. Figure D.24 illustrates how temperature tolerance varies with exposure time at several different acclimation temperatures, and the bar chart in Figure D.25 shows where various species rank in their ability to tolerate excess temperature. Both figures indicate that the majority of the most commonly occurring species fall within the mid range in tolerance to elevated temperature. The more sensitive species are primarily trout and salmon. In general, the majority of species other than trout and salmon can be protected by protecting the most commonly occurring species, or certain indicator species such as walleye.

In summary, many factors influence the selection of a representative species on which to base the design of a generating station cooling system. The cooling system should be designed to minimize cooling water volume by operating as near as possible to the temperature tolerance level of the selected representative important fish species entrained. Where the appropriate data are available, the NAS/NAE formula can be applied to determine the temperature at which protection is provided (assumed to be 2°C

TABLE D.9 APPROXIMATE EXPOSURE TIMES TO MAXIMUM TEMPERATURE AT SOME EXISTING AND PROPOSED CANADIAN STATIONS

Station	Exposure time (minutes)*								Reference
	1 unit	2 units	3 units	4 units	5 units	6 units	7 units	8 units	
1313	2.5								(85)
1415	3.9								(85)
3104	20.0	10.0	6.7	5.0	3.3	2.5	2.0	1.7	(85)
3105	21.8	10.9	7.3	5.4	4.3	3.6	3.1	2.7	(85)
3106	50.0	20.0	12.5						(85, 98)
3108	5.6	4.2	2.8	1.4					(85)
3109	26.7	13.3	8.9	6.7	5.3	4.4	3.8	3.3	(85)
3111	18.8	9.4	6.2	4.7					(85)
3115	25.4	12.7	8.5	6.4					(85)
3209	18.4	9.2	6.1	4.6					(85)
4208	253	127							(24)
4318	560	280	132	63.3					(85)

* Exposure times listed are for discharge conveyance facility (channel, tunnel or pipe) only.
Exposure times for maximum number of units estimated from lengths of conveyance facility and maximum flow velocity.
Exposure times for fewer than maximum number of units estimated by increasing maximum unit exposure time in proportion to reduced cooling water flow.

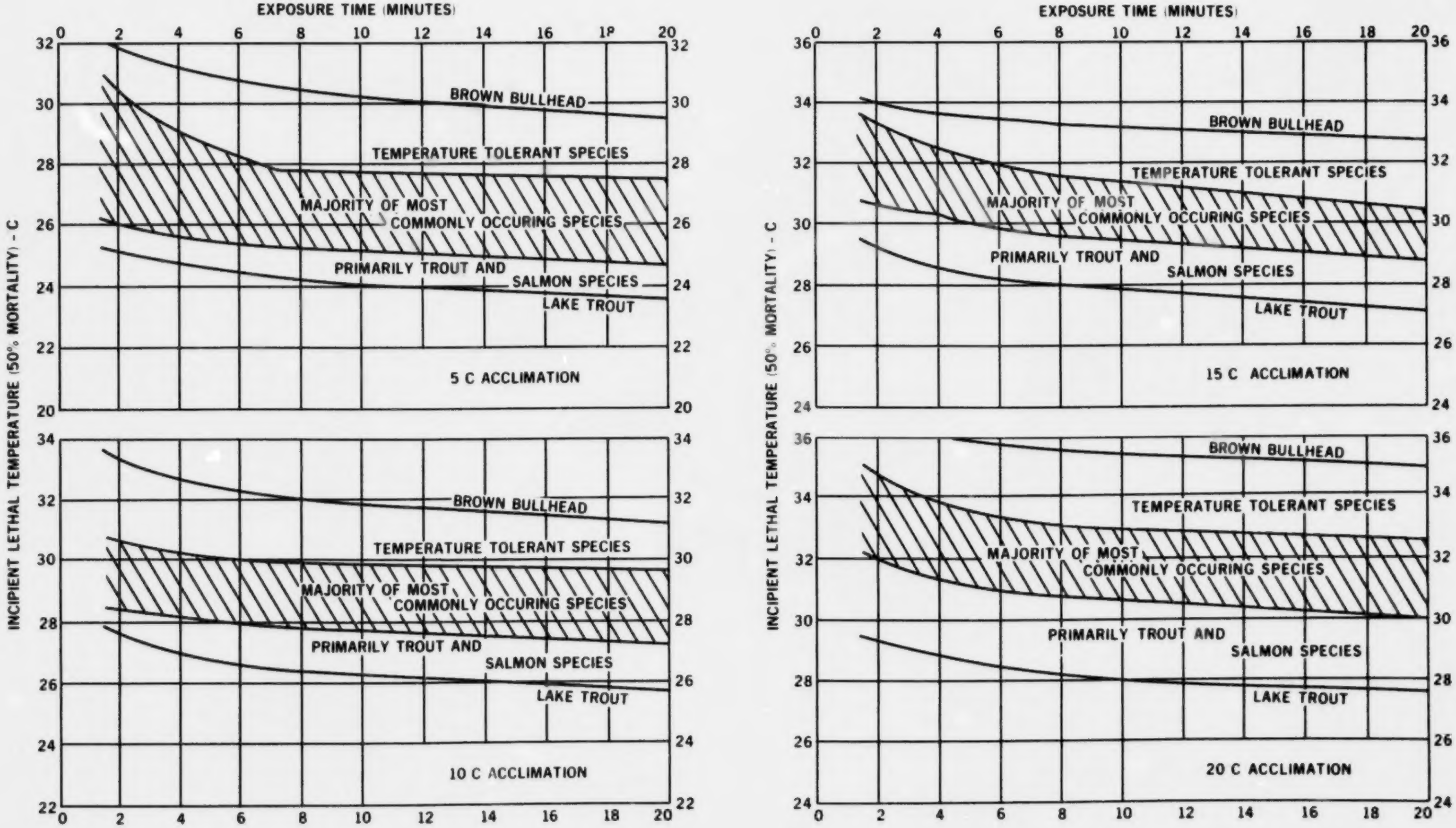


FIGURE D.24 UPPER LETHAL TEMPERATURES VERSUS EXPOSURE TIME FOR SELECTED FISH SPECIES AND ACCLIMATION TEMPERATURES.

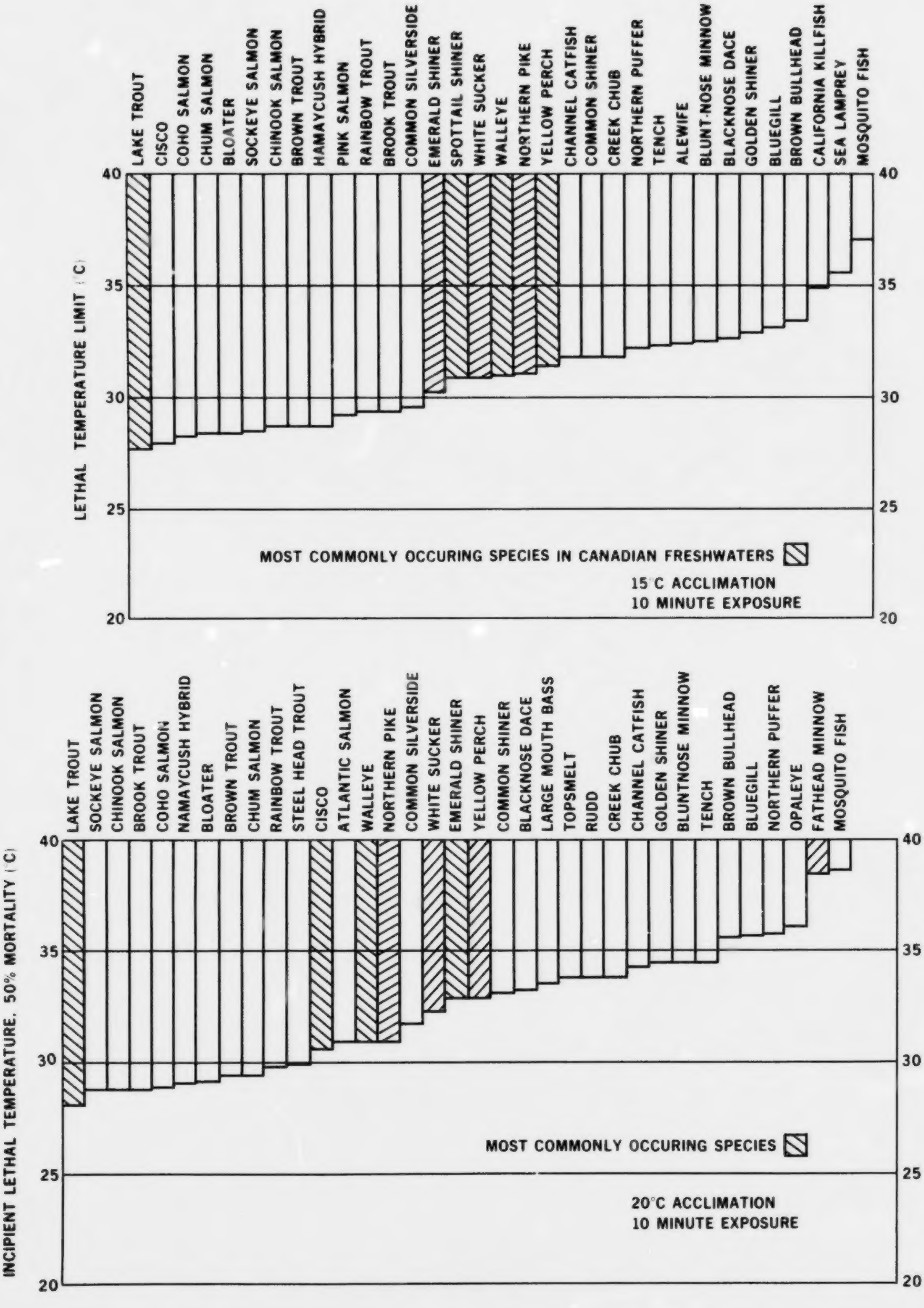


FIGURE D.25 SELECTED FISH SPECIES RANKED IN ORDER OF INCIPIENT LETHAL TEMPERATURE

below the 50 percent mortality temperature). In the absence of appropriate data on the fish species at a particular site, additional temperature tolerance studies may have to be undertaken.

(b) Annual Temperature Rule Curve. As discussed in the previous section, many factors influence the target temperature for design and operation of a generating station cooling system. Such factors as seasonal differences in representative important fish species require that cooling systems be designed with a certain degree of flexibility to vary the flow and thereby the temperature rise in the condenser. There are, however, practical limits to this flexibility. It may be difficult for a station to respond immediately to an entrainment problem that was unforeseen or not considered important when the cooling system was designed. It may also be a major undertaking to alter the cooling system design and operation at an existing plant to protect a more sensitive species if it had initially been designed to protect a relatively temperature tolerant species. It is desirable that a clearly defined target temperature for the design and operation of a new station be established and agreed upon by the power utility and the responsible environmental agency. Such a target temperature would account for known seasonal variations in fish species and ambient water temperature, short-term requirements for alterations to normal operating procedures and preferred periods for maintenance outages at a particular site. It could best be defined by an annual temperature rule curve comparable to annual operational rule curves for reservoirs at hydro-electric stations. An example of an annual temperature rule curve is provided in Figure D.26. Such a rule curve provides a visible, agreed upon target for maximum condenser discharge temperature throughout the year that will best achieve the combined objectives of minimizing entrainment of aquatic organisms and protecting those that are entrained.

(c) Exception to General Provision. As discussed earlier, there is no point in imposing a temperature limit to protect entrained fish if they are already killed by chemical or physical stresses. If chemically and/or physically induced mortality is high, total losses will be minimized by operating at a higher condenser discharge temperature to minimize intake water volume.

Analyses of some typical condenser temperature rises for power plants operating on source water bodies with different natural temperature regimes show that with a warm water lake, such as Lake Erie, it is not advantageous to remove the temperature limit in favour of lower water volumes unless mortality from other causes is

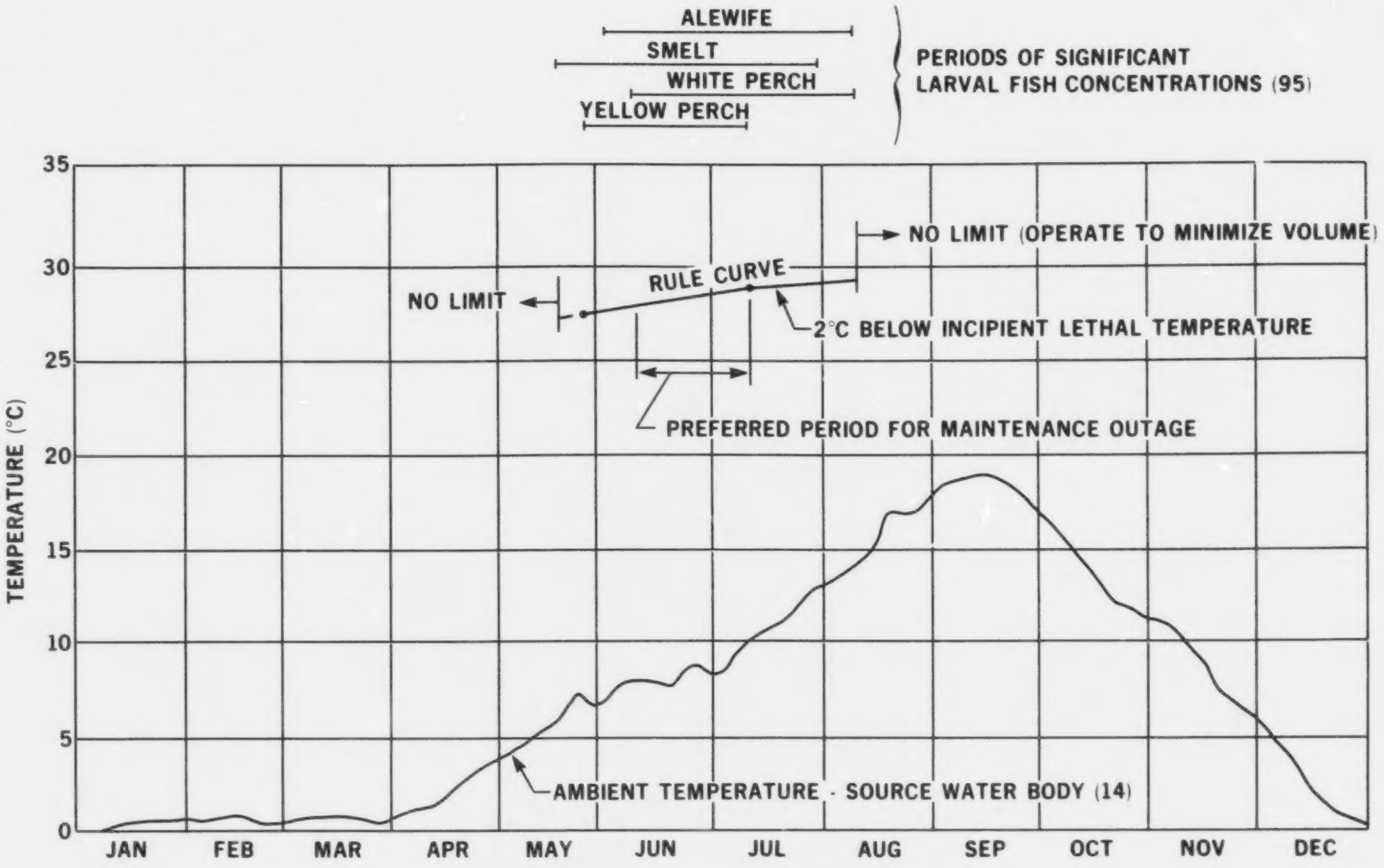


FIGURE D.26 EXAMPLE OF ANNUAL TEMPERATURE RULE CURVE FOR A STEAM ELECTRIC GENERATING STATION

greater than 50 to 60 percent of the numbers of organisms entrained. For a colder lake, such as Lake Ontario, damage from other causes must be 60 to 70 percent of the numbers entrained.

An assessment of whether or not it would be advantageous to drop the temperature rule curve limit should be conducted if extensive physical damage or prolonged lethal chemical dosage is expected in a particular situation. Before the temperature rule curve limit is removed, it should be clearly demonstrated that a high rate of non-temperature induced mortality is unavoidable.

Maintaining condenser discharge temperatures as high as technically feasible, and thereby reducing cooling water volume, will increase the chances of temperature-induced damage to organisms entrained in or trapped by the thermal plume. Therefore increased temperatures will be appropriate only if other measures are taken to reduce the impact of thermal discharges. Such measures are described in recommendations R114 and R115 relating to the size of thermal plumes and the location and design of cooling water discharges.

The following temperature control criteria are recommended:

Recommendation R113

(i) ***The temperature at the downstream end of each condenser should be maintained as high as possible without causing temperature-induced mortality of the representative important fish species entrained. Temperature is assumed to be non-lethal 2°C below the 50 percent mortality temperature.***

(ii) ***Where it is demonstrated that most or all of the entrained ichthyoplankton (fish eggs and larvae) of representative important species are killed by physical stress or chemical exposure, the temperature limits defined by part (i) should be removed and the system operated such that the temperature at the discharge end of each condenser is maintained as high as technically feasible.***

(iii) ***An annual temperature rule curve consistent with parts (i) and/or (ii) should be established for each station taking into account seasonal variations in susceptible fish species.***

D.6 Minimization of Detrimental Effects from Heated Discharges

D.6.1 General

The outfall section of a once-through cooling water system encompasses those elements of the system from the downstream side of the condenser or heat exchanger, at which point the water has served its cooling function, to its discharge into the receiving water. In Canada, the majority of outfalls are either large open channels or buried pipes discharging near shore. In some cases, tempering water is added to the cooling water after passage through the condenser in order to meet a maximum temperature criterion before release to the receiving water body.

The area affected by a heated discharge depends on the cooling water flow rate and discharge temperature, the outfall location and design, and the temperature and natural dispersion characteristics of the receiving waters. The thermal plume from a large generating station with a shoreline surface discharge can have a surface area of several square kilometres. Unless the plume is physically confined, it will normally continually shift in shape and location depending on the wind and current. With calm weather and low velocity currents, the plume may extend offshore in the direction of the discharge. Conversely under the influence of a strong longshore current, the plume may be conveyed relatively undispersed for a considerable distance along the shoreline.

The effects of heated discharges on aquatic ecosystems are well documented (2, 13). Some of the common concerns are listed below:

(i) The reproductive success of fish can be adversely affected by the elevated temperatures of a thermal plume in waters used for spawning, incubation and nursery of newly hatched larvae. Fall spawning can be delayed and spring hatching advanced resulting in shortened egg incubation periods. This in turn may cause reduced hatching success, formation of abnormal larvae and poor survival rates of larvae released prematurely into conditions where temperature, light and food resources are sub-optimum.

(ii) Altered temperature regimes may render normal spawning areas unsuitable for some species thereby reducing the availability of favourable spawning areas.

(iii) Sinking plumes which move downward and impinge on the benthos during the winter months can cause premature fish egg hatching and reduced rates of larval and juvenile fish survival.

(iv) A decline in the populations of fish species that frequent the nearshore zone (e.g., yellow perch, cisco and emerald shiner in freshwater) but spend part of their life cycle offshore providing food supply for deepwater species (e.g., lake trout, whitefish and burbot) may lead to a decline in the deepwater fish populations.

(v) Shifting of the thermal plume and impinging of the plume on the shoreline may trap certain species in waters that exceed their upper lethal temperature limits. Similarly, lower lethal temperature exposure can occur if species residing in a thermal plume are suddenly exposed to the surrounding colder ambient temperatures because of a plant shutdown or a shift in the plume location.

(vi) The plume may act as a barrier to the natural movement of fish between the nearshore and offshore waters, to diurnal vertical migration for feeding, or to seasonal migration for spawning.

(vii) There is evidence that the incidence of fungal and bacterial fish diseases increases as water temperature increases (99). These diseases are not restricted to adults, but can occur as early as the egg stage. Increased levels of parasitism in fish have also been observed when ambient water temperatures are raised (100).

(viii) The accumulation of toxic substances such as heavy metals and pesticides occurs at a faster rate in fish exposed to elevated temperatures. The consequences of these effects on fish will be reduced vigor and lowered fitness levels of the populations. In addition, the affected fish may be less desirable or unfit for human consumption or other uses.

(ix) Large open water areas maintained by the heated discharge in winter encourage overwintering of waterfowl. Increased incidence of clostridium disease has been observed in waterfowl inhabiting these warm waters and exposure of fish to waterfowl hosting fish parasites is increased. Food will likely be in short supply, possibly leading to starvation of the birds. In addition, power reduction or outages can temporarily reduce or even eliminate the ice-free area, destroying water fowl dependent on that area.

(x) Heated discharges into nutrient-rich waters can stimulate excessive algae and weed growth rendering large areas unsuitable for other uses.

Since, as discussed previously, the nearshore zone in most water bodies has a high biological productivity, control requirements for heated discharges must be designed to protect nearshore waters. The most effective way to protect these waters, although it is by necessity somewhat arbitrary, is to limit the area of influence of the thermal plume within the nearshore zone. It is considered that adequate baseline protection for the nearshore waters is provided if thermal plumes do not occupy more than 10 percent of the nearshore zone water surface area within designated segments of shoreline.

For the purpose of this code:

A thermal plume is defined as that part of the water body where the temperature is elevated 1°C or more above the ambient water temperature by the discharge of heated condenser and/or auxiliary cooling water.

The area of a thermal plume defined in this manner will vary during the year and with differing dispersion conditions. For design purposes the area of the thermal plume should be the maximum area expected under worst daily dispersion conditions and summer conditions.

Although protecting the nearshore waters is of primary importance in most water bodies, additional considerations exist in the case of small water bodies and rivers. The complete blockage of fish migration routes is of concern in both small lakes and rivers when no other barrier to migration exists (e.g., natural waterfalls or dams with no fish bypass provision). It is imperative that the thermal plume does not extend across a river or small water body to the opposite shore, creating a thermal barrier to the free movement of fish either upstream or downstream or from one segment of the water body to another.

Another concern in small lakes and reservoirs is warming of the entire epilimnion and/or depletion of the hypolimnion (see Figure D.27). Warming of the entire water body may adversely alter fish spawning and egg development conditions throughout the entire system. This is of particular concern in winter when the plume sinks and extensive areas of the lake bottom are covered with water at 4°C. With the persistance of such conditions, the successful and normal development of fish spawn, such as that for whitefish, would certainly be endangered (13). In addition, the larger the percentage of lake area the heated region occupies, the greater the number of fish, particularly cold water species, attracted to the area. This is likely to retard fall spawning and advance spring spawning with the inherent adverse affects discussed earlier.

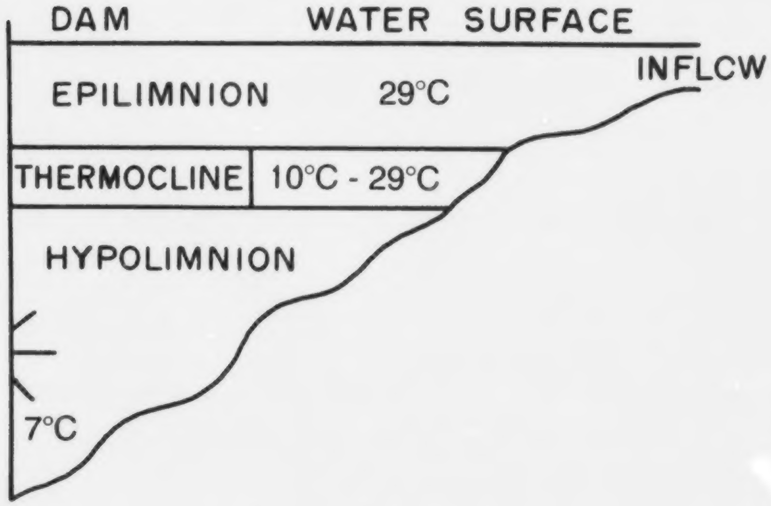


FIGURE D.27 TYPICAL STRATIFIED RESERVOIR PROFILE (101)

Other potential problems arise when heated discharges affect a large percentage of the water body. Conditions suitable for certain native species may no longer exist and, eventually, those species may be replaced by more temperature tolerant (and often less desirable for commercial or recreational purposes) species. For example, as the hypolimnion is depleted (thermocline lowered), the preferred habitat for cold water species, such as trout, is diminished, threatening their continued existence in that water body.

As with limitations on area of influence in the nearshore, any limitation on the area and degree of influence of a heated discharge in a small water body is somewhat arbitrary. However, some baseline level of protection against system-wide effects is necessary to ensure the biological preservation of such systems. This protection can be provided by imposing one or both of the following constraints:

(i) a limit on the average temperature rise over the entire water body,

(ii) a limit on the percent of lake surface area occupied by a given isotherm of the thermal plume.

It is considered that an adequate baseline level of protection is provided in small water bodies by limiting the area occupied by the thermal plume (as defined by the 1°C isotherm) to 10 percent of the surface area of the water body. In most cases this is expected to ensure that the average lake wide increase in temperature over the original ambient is less than 1°C.

Since the following recommendations relating to outfall design are expected to result in good potential for fish avoidance of maximum (and possibly lethal) plume temperature areas, a maximum temperature within the plume is not necessary for protection of fish in the receiving waters. Any maximum discharge temperature imposed for protection of entrained fish would indirectly impose an upper limit on the plume temperature, but not one specifically devised to address any receiving water concern.

In summary, the primary concerns with heated discharges are adverse effects on the biological productivity of the nearshore waters of all water body types coupled with special concerns asociated with system-wide effects in small water bodies and rivers. The following area of influence limitations are recommended to minimize these effects:

Recommendation R114. Unless it is demonstrated that a greater area of influence is no more detrimental environmentally, the thermal plume (as defined by the 1°C isotherm) from a generating station should not, when combined with thermal plumes from other sources, cause the combined area occupied:

(i) within the 50 km segment of nearshore zone on which the station is centred, to be greater than 10 percent of the total nearshore zone surface area for that segment in all water body types except rivers;

(ii) within the 50 km segment of nearshore zone downstream from the generating station on a river to be greater than 10 percent of the total nearshore zone surface area for that segment;

(iii) to be greater than 10 percent of the total surface area of a lake or reservoir;

(iv) to be such that more than 50 percent of the distance across the surface at any location on a river, lake or reservoir is occupied.

D.6.2 Selection of Outfall Type, Location and Design

(a) Description of Outfall Types. The type of outfall is determined by several factors:

(i) onshore or offshore;

(ii) surface or submerged - the top of the discharge pipe should be at least one pipe diameter below the water surface to be termed submerged;

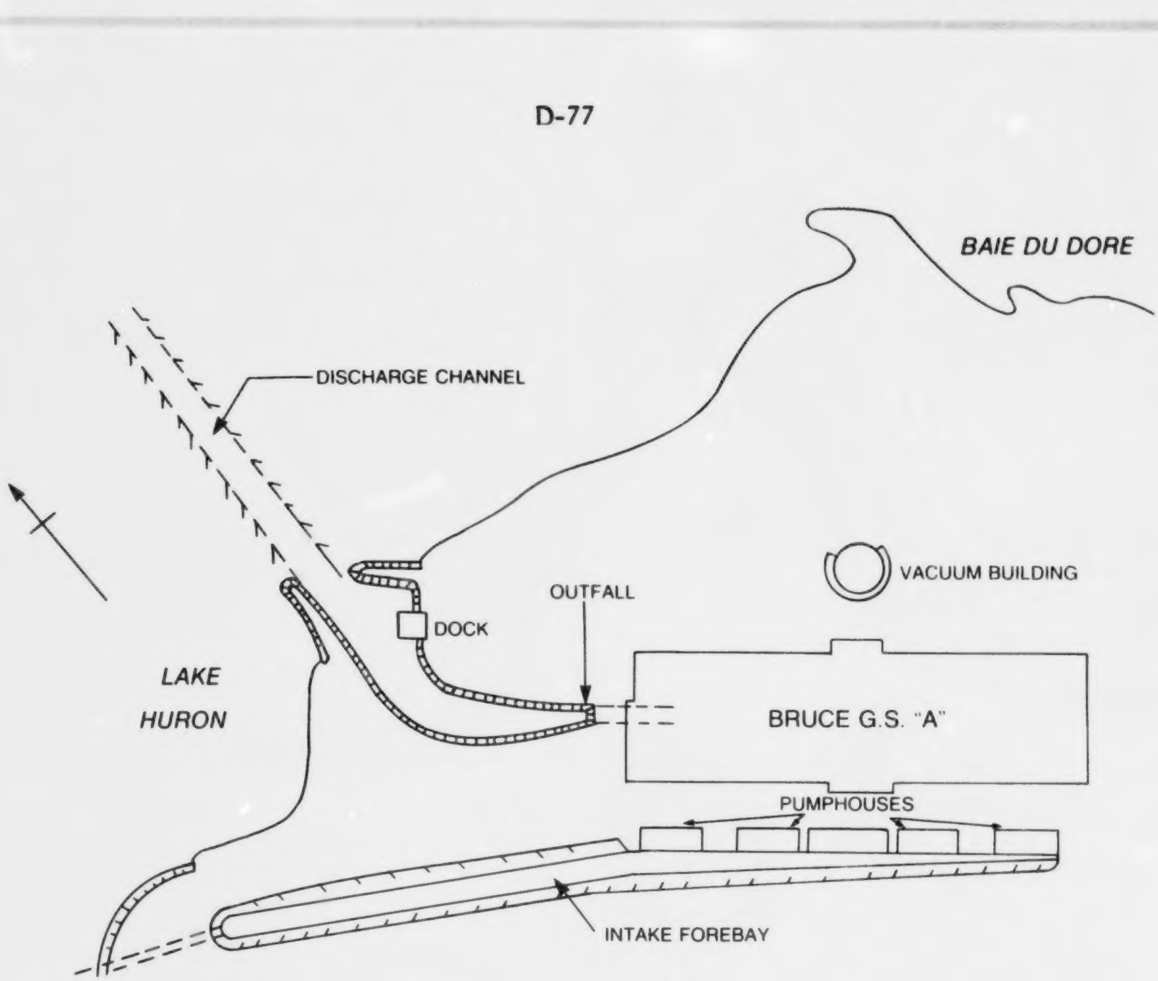
(iii) low or high velocity discharge - 3 m/s or greater should be considered high velocity;

(iv) single or multiple discharge ports.

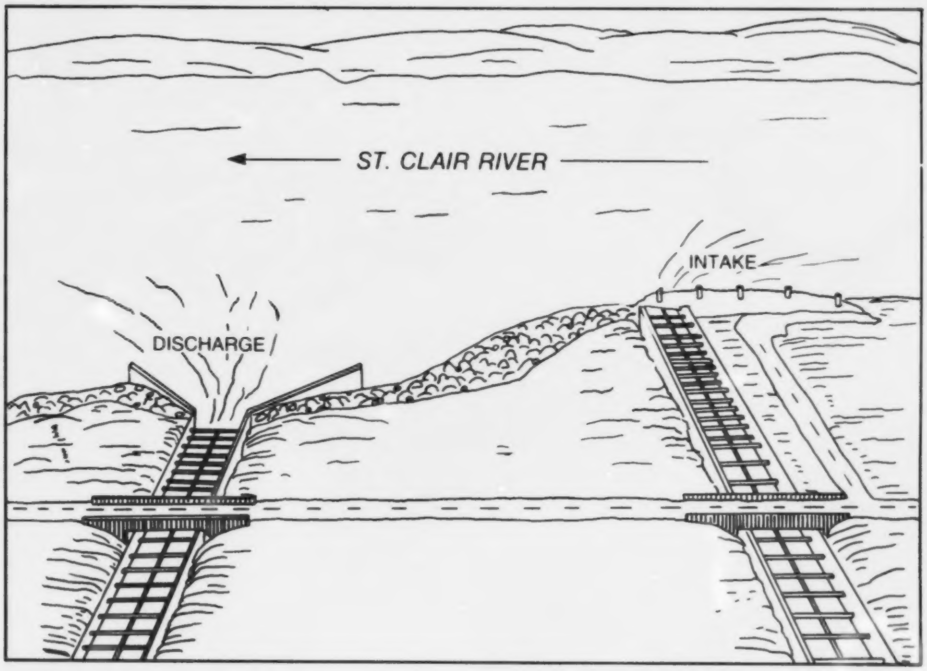
The most common cooling water outfall at Canadian generating stations is a low velocity, surface discharge at or near the shoreline. An open channel is most frequently used to convey the heated water from the condenser discharge pipe to the receiving water body. These channels vary in length from less than 100 m to several kilometres. Two examples of shoreline surface discharges are illustrated in Figure D.28. Low velocity surface discharges ordinarily form a very large, shallow surface plume which promotes the dissipation of heat to the atmosphere. Typical plume configurations and a typical centreline profile for a surface discharge plume are illustrated in Figure D.29.

Offshore outfalls are basically outfalls with an ultimate discharge point some distance from the shoreline. A submerged pipe, an underground pipe or tunnel, or parallel groins may be used to convey the heated water offshore for release. Two examples of outfall tunnel arrangements are illustrated in Figure D.30.

The parallel groin or dyke arrangements usually create a surface plume similar to shoreline outfalls, with the plume size dependant on the outfall velocity and degree of mixing with ambient water. Outfalls with tunnel or pipe conveyance can create various plume configurations and temperature regimes in the local receiving waters depending on the release mechanism and the depth, direction and velocity of the discharge. With low

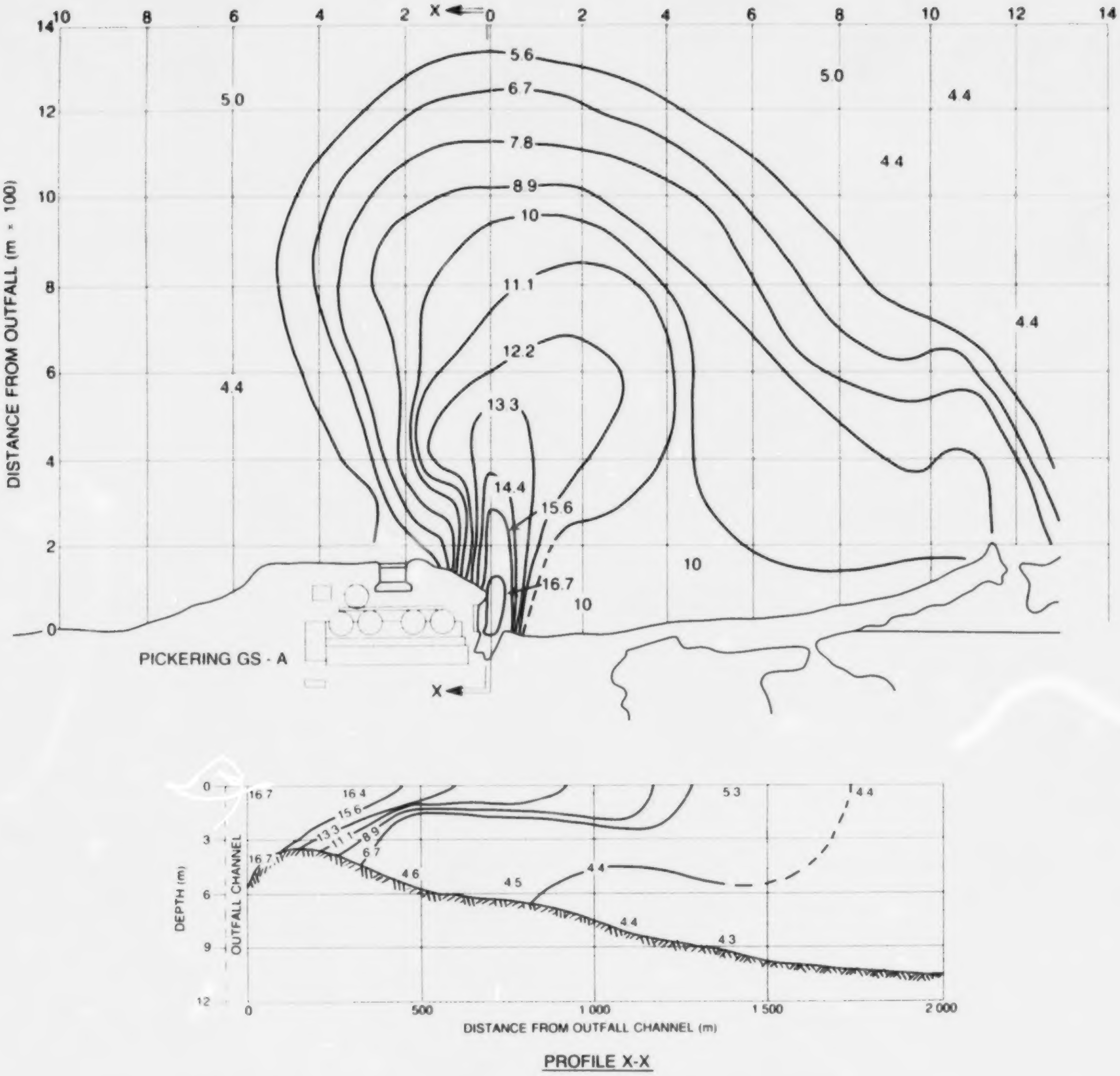

BAIE DU DORE
DISCHARGE CHANNEL
VACUUM BUILDING
OUTFALL
DOCK
LAKE
HURON
BRUCE G.S. "A"
PUMPHOUSES
INTAKE FOREBAY

(a) Bruce A Nuclear Generating Station - Lake Huron (9)

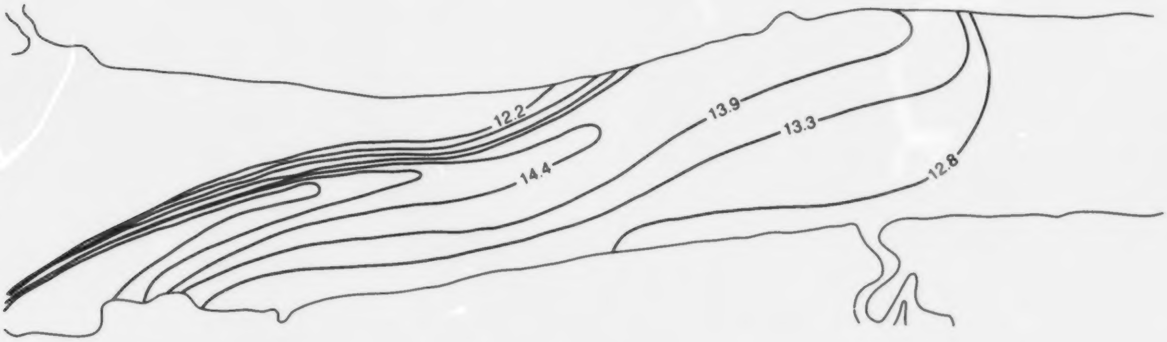

ST. CLAIR RIVER
INTAKE
DISCHARGE

(b) Lambton Generating Station - St. Clair River (102)

FIGURE D.28 EXAMPLES OF SHORELINE, SURFACE DISCHARGES

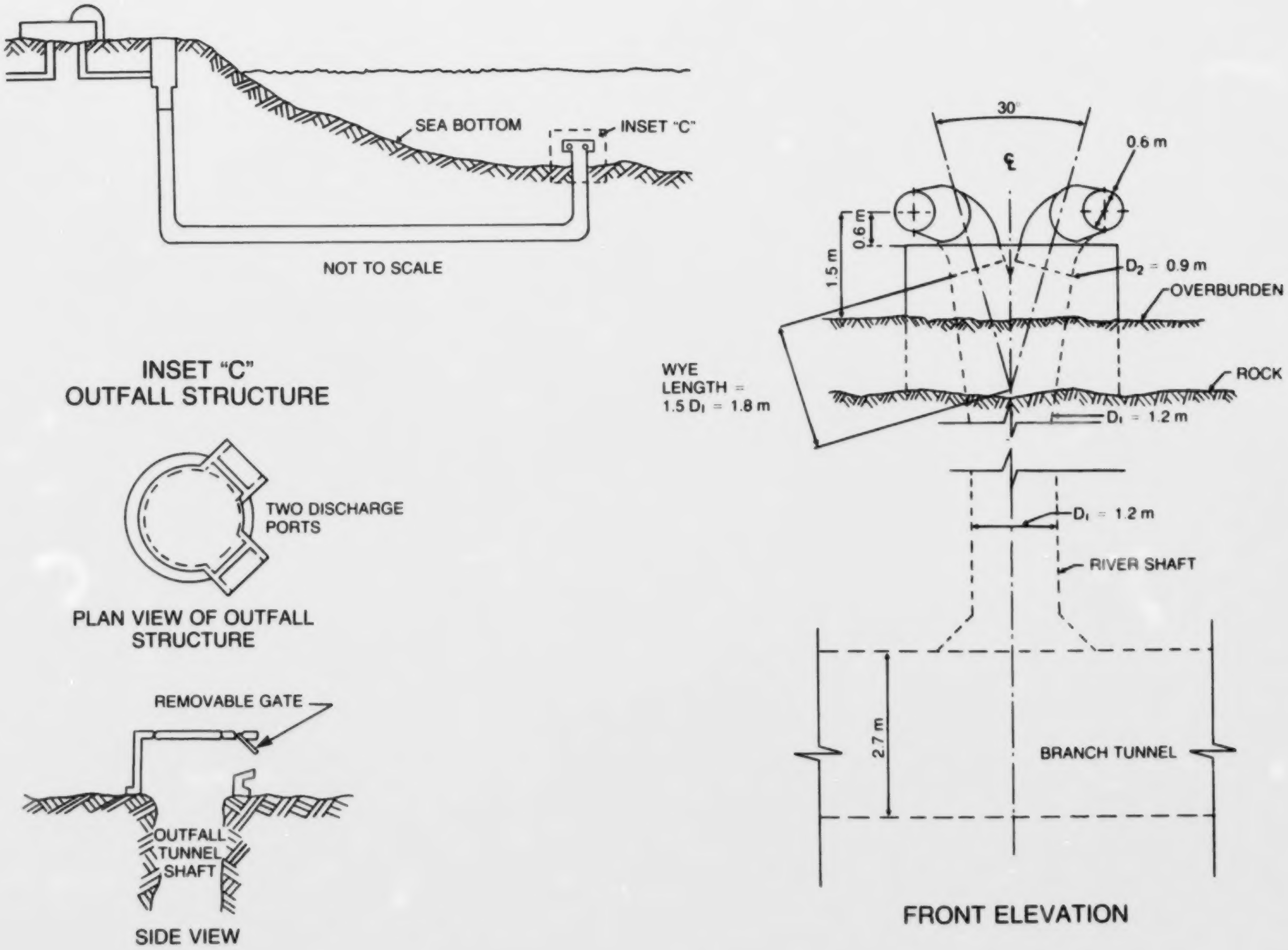


(a) Pickering A Nuclear G.S. - Thermal Plume Plan and Profile (103)


12.2
13.9
13.3
14.4
12.8

(b) Widow Creek G.S. on Tennessee River (104)

FIGURE D.29 TYPICAL THERMAL PLUMES FROM ONSHORE OUTFALL


SEA BOTTOM
INSET "C"
NOT TO SCALE
INSET "C"
OUTFALL STRUCTURE
TWO DISCHARGE PORTS
PLAN VIEW OF OUTFALL STRUCTURE
REMOVABLE GATE
OUTFALL TUNNEL SHAFT
SIDE VIEW
30°
℄
0.6 m
0.6 m
1.5 m
D2 = 0.9 m
OVERBURDEN
ROCK
WYE LENGTH = 1.5 D1 = 1.8 m
D1 = 1.2 m
D1 = 1.2 m
RIVER SHAFT
2.7 m
BRANCH TUNNEL
FRONT ELEVATION

(a) Point Lepreau G.S. - Bay of Fundy (44)

(b) Oswego G.S. - Lake Ontario (105)

FIGURE D.30 EXAMPLES OF OFFSHORE DISCHARGES

velocity, single-port submerged discharges, the heated water may simply rise to the surface creating a thin surface plume. Higher velocity, multi-port submerged outfalls will entrain a considerable amount of local ambient water into the discharge flow stream thereby diluting the heated discharge, and causing a rapid temperature reduction in the released water. The areal extent of high excess temperatures is minimized, but the volume of water affected is greater.

The flow regions typically encountered with an offshore submerged discharge are illustrated in Figure D.31.

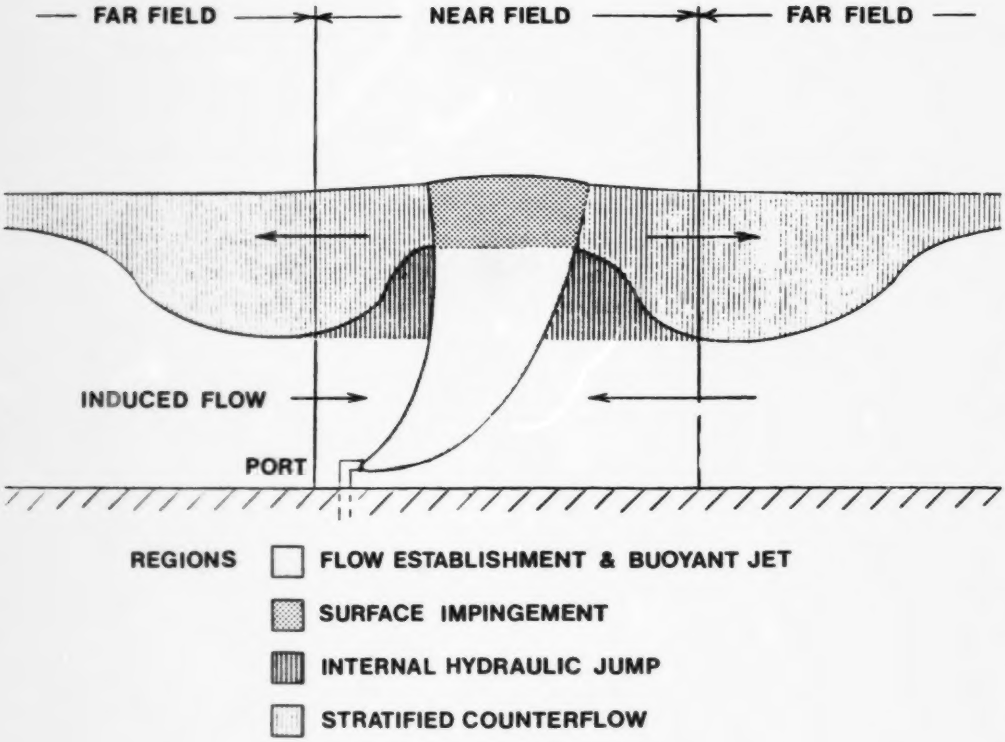

FAR FIELD
NEAR FIELD
FAR FIELD
INDUCED FLOW
PORT
REGIONS
FLOW ESTABLISHMENT & BUOYANT JET
SURFACE IMPINGEMENT
INTERNAL HYDRAULIC JUMP
STRATIFIED COUNTERFLOW

FIGURE D.31 TYPICAL FLOW REGIONS FOR AN OFFSHORE SUBMERGED DISCHARGE (106)

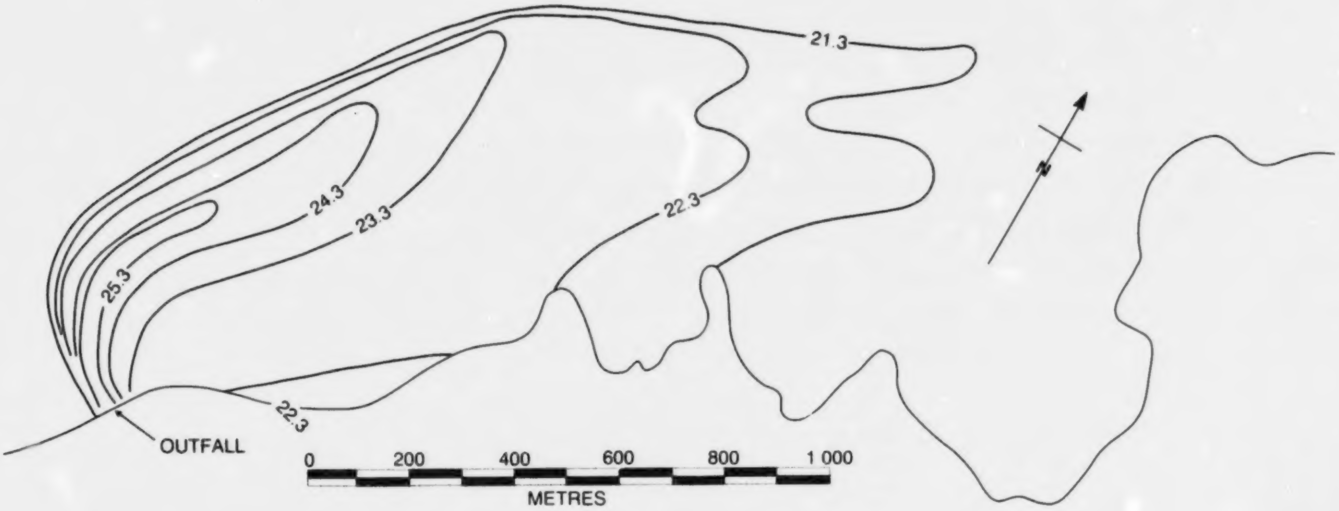
(b) Outfall Location and Design to Minimize Environmental Impact. Because of the importance of nearshore waters for fish spawning, rearing, feeding and migration, cooling water outfalls should be located and designed to minimize the area of influence of the thermal plume in the nearshore zone.

Onshore outfalls discharge large quantities of heated water directly into the nearshore zone. In the absence of strong longshore currents and with a fairly rapid increase in depth offshore, the surface plume generated may not impinge on the shoreline and is likely to provide good opportunities for downward avoidance by fish. However, when the plume is conveyed longshore by currents, it will occupy the shallower nearshore waters where even a surface plume will impinge on the bottom. Fish are then trapped against the shoreline in waters of elevated temperature with little opportunity to escape beneath the plume. Also, fish spawning areas and areas of high concentration of fish eggs and larvae will be subjected to the excess temperatures.

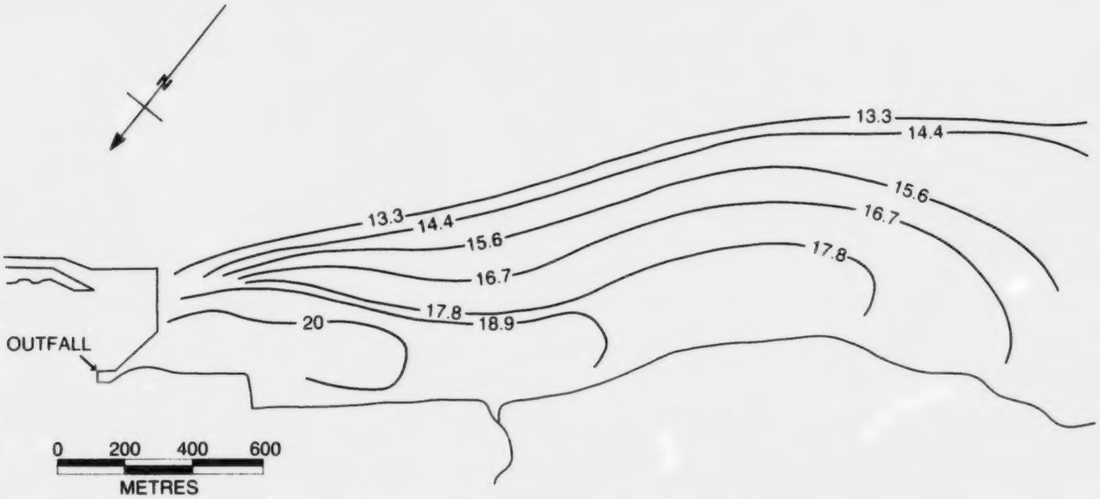
Figure D.32 shows measured configurations of thermal plumes in two large water bodies and a large river. This illustrates the tendency for the plume to elongate along the shoreline downstream in the presence of longshore currents, and indicates the extent of nearshore waters that can be affected. In lakes, reservoirs, estuaries or oceans where current reversals occur, significant shoreline lengths in both directions from the outfall can be affected.

Properly designed offshore outfalls will minimize the area of influence of the thermal plume within the nearshore zone. Occasional incursions of heated water into the nearshore zone can further be reduced by effective design and orientation of the release structure. A fairly high velocity discharge directed away from the shoreline will reduce the susceptibility of the plume to be bent shoreward by longshore currents. Alternative submerged outfall designs include single port, twin port and multiple port (diffuser) release structures. Multiple discharge ports on the outfall increase the rate of dilution of the heat and cause greater horizontal spreading of the plume in comparison to a single-port discharging the same total flow. The momentum and distance of projection offshore are reduced and there may be a somewhat greater tendency for a lower temperature plume to be swept shoreward by winds and currents.

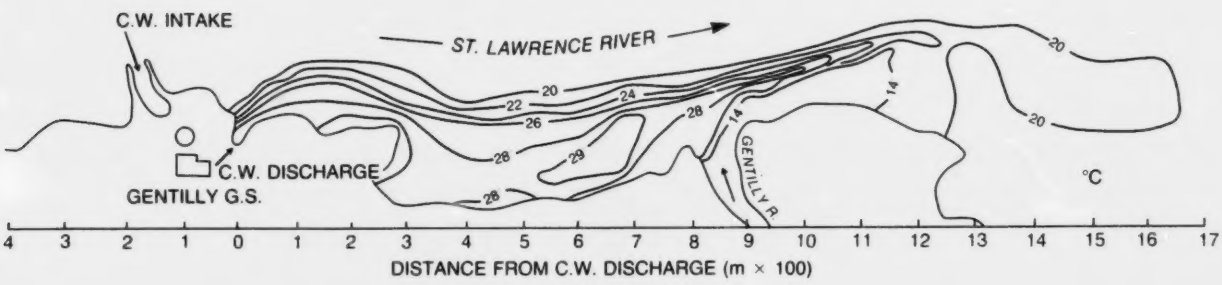
Some potential disadvantages accompany high velocity, offshore discharges. One is an increase in the time of exposure to maximum temperature because of a greater conveyance time from the condenser to the point of ultimate release to the receiving waters. Figure D.33 has been used frequently to indicate typical exposure times for alternative outfall types. Although the time of exposure to near maximum temperatures may be greater with an offshore outfall, the duration of exposure to substantially elevated temperatures is less. This is particularly true when compared with a low velocity, shoreline discharge that is conveyed relatively undispersed along the shoreline by longshore currents.


21.3
24.3
23.3
22.3
25.3
22.3
22.3
N
OUTFALL
0
200
400
600
800
1 000
METRES

(a) Douglas Point Nuclear G.S. - Lake Huron (107)


N
13.3
14.4
15.6
16.7
13.3
14.4
15.6
16.7
17.8
17.8
18.9
20
OUTFALL
0
200
400
600
METRES

(b) Lakeview G.S. - Lake Ontario (107)


C.W. INTAKE
ST. LAWRENCE RIVER
20
22
24
26
28
29
28
14
14
GENTILLY R.
20
20
°C
C.W. DISCHARGE
GENTILLY G.S.
4
3
2
1
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
DISTANCE FROM C.W. DISCHARGE (m × 100)

(c) Gentilly Nuclear G.S. - St. Lawrence River (108)

FIGURE D.32 EXAMPLES OF THERMAL PLUMES ELONGATED ALONG SHORELINES

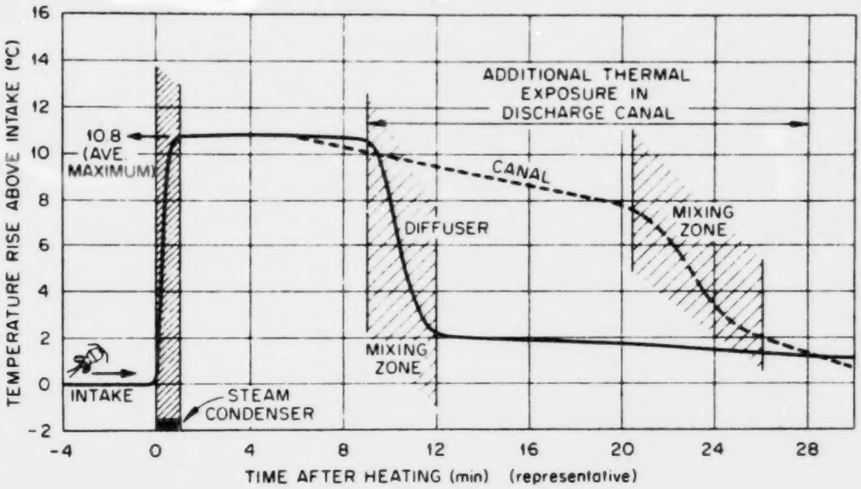


FIGURE D.33 RELATIVE EXPOSURE TIME FOR DIFFUSER AND DISCHARGE CHANNEL OUTFALLS (109)

Another potential disadvantage of a high velocity offshore discharge is scouring of the lake or ocean bed. This can be largely avoided by elevating the discharge ports above the bed and directing them at an angle upwards from the bed. The diffuser discharge ports shown in Figure D.34 are oriented to maximize dilution with ambient water and minimize disruption of the river bed downstream.

High velocity flow through a relatively small discharge port will also generate considerable turbulence and shear stress both on the organisms entrained in the discharge water and those that are subsequently entrained from the ambient water into the plume. Minimizing the numbers of ichthyoplankton exposed to these stresses through a combination of intake siting and design to reduce initial entrainment into the cooling water flow, and locating the outfall beyond the nearshore zone to minimize plume entrainment should substantially alleviate this concern. Further, diffuser discharge ports are orders of magnitude greater in size and will exert considerably less stress, than the condenser tubes through which the organisms have already passed.

In general, the environmental advantages of discharging heated cooling water offshore far exceed the disadvantages. A basic criterion for outfall location and design is that the heated water should be discharged beyond the nearshore zone unless it can be demonstrated that an onshore outfall or an offshore outfall located within the nearshore zone is no more detrimental environmentally.

The method of conveying the heated water from the generating station to the offshore location can also have significant environmental implications. Most offshore submerged outfalls employ large underground tunnels. Tunnelling is preferred

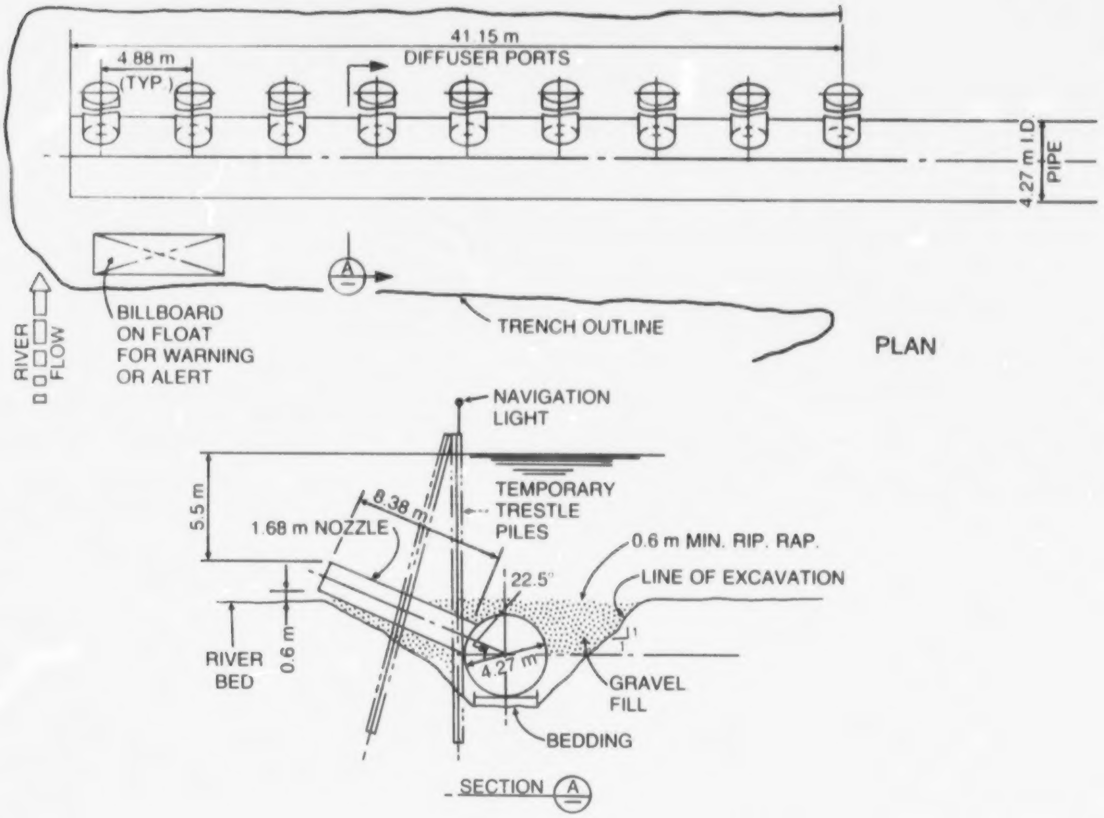

41.15 m
DIFFUSER PORTS
4.88 m
(TYP.)
4.27 m I.D.
PIPE
BILLBOARD ON FLOAT FOR WARNING OR ALERT
TRENCH OUTLINE
PLAN
RIVER FLOW
A
NAVIGATION LIGHT
TEMPORARY TRESTLE PILES
5.5 m
1.68 m NOZZLE
8.38 m
22.5°
0.6 m MIN. RIP. RAP.
LINE OF EXCAVATION
1
1
RIVER BED
0.6 m
4.27 m
GRAVEL FILL
BEDDING
SECTION A

FIGURE D.34 OFFSHORE SUBMERGED DIFFUSER FOR BELLE RIVER POWER PLANT (42)

environmentally to laying a pipe on the lake, ocean or river bed, trenching a pipe or excavating a channel into the bed, or constructing parallel dikes or groins to convey the heated water offshore. The laying of pipe in a trench may have only a temporary impact whereas laying of pipe on a lake bed or construction of groins will have a permanent impact. All of these alternatives require that a considerable area of lake bed be altered with corresponding disruption to benthic communities. This disruption may extend beyond the immediate construction area due to silt dispersal and deposition. Alternatives that require excavation or trenching in the bed material tend to create areas along the bottom where fish will congregate. These may be the excavated channel itself, or piles or ridges of excavated material that will attract fish and/or guide them along abnormal migration paths. Any physical obstruction across the nearshore zone, such as a large pipe on the lake or ocean bed or groins extending offshore, will alter current patterns, sediment deposition patterns, and fish movement in the nearshore waters. Again, fish will congregate in sheltered areas around these structures, and currents induced on the downstream side will tend to draw the thermal plume shoreward.

Fish may take up residence and even spawn in low velocity discharge channels (110). The poor condition often noted in fish residing in discharge channels may stem from the lack of sufficient food organisms in the flow to balance a metabolic rate that has been elevated by the high temperature and constant current. Fish residing in a discharge channel will become acclimated to the elevated temperature and be susceptible to cold shock mortality in the event of a total plant shutdown. This problem is less severe in multi-unit stations where it would be unusual for all units to go down simultaneously.

A number of measures can be taken to prevent the entrance and residence of fish in discharge channels. These include maintaining high channel and outfall velocities or providing a physical barrier, such as an overflow weir, at the outlet. A high outfall velocity is not always easily maintained, however, since multi-unit stations are often operated at less than maximum capacity. This may make physical barrier alternatives more effective. In any event, where channel outfalls have been demonstrated to be an acceptable alternative to an offshore outfall, the channel should be designed to prevent fish entrance and residence.

In summary, cooling water outfalls should be located and designed to ensure minimum interaction of the plume with the nearshore zone, and minimum interference with natural currents and behavioral patterns of fish within that zone. For this purpose the following measures are recommended:

Recommendation R115. ***Unless it is demonstrated that an alternative outfall location and/or design is no more detrimental environmentally:***

(i) ***once-through cooling water should be discharged beyond and directed away from the nearshore zone;***

(ii) ***the method of cooling water conveyance from the generating station to the release point in the receiving water body should be a tunnel or buried pipe.***

D.6.3 Helper Cooling Systems

Helper systems are supplementary cooling devices operating in the outfall section of a generating station to reduce the temperature of the discharge. They may be considered for installation on once-through cooling systems to reduce the area of influence of the thermal plume or to resolve some other site-specific concern with the heated discharge.

Helper cooling systems can be divided into two categories: those that require excess water and those that do not. Those requiring excess water are known as tempering systems. Tempering water is taken from the forebay by separate pumps, pumped around the condenser and mixed with the condenser discharge water to effect a temperature reduction. A similar effect is achieved by withdrawing from service or derating one unit at a multi-unit station while maintaining the cooling water pumps at full capacity. In these cases, volumes of water in excess of that required for the removal of heat from the condensers are pumped through the generating station, with the potential for additional loss of entrained organisms.

Helper systems that require no excess volumes of water include cooling ponds or canals, spray ponds or canals, or cooling towers. Such systems may be used to reduce the discharge temperature by processing the entire flow directly, or by cooling only a part of the flow by a larger amount and subsequently blending it with the unprocessed portion. The actual degree of temperature reduction depends directly on the size, design, and flow-through rate of the helper system.

In helper systems that use excess water for tempering the heated water discharge, the tempering pumps are the primary cause of damage to entrained fish. At two existing installations using common cooling water pumps for conveying tempering water, total mortality of entrained fish occurs (28). However, since tempering pumps can operate at a very low hydraulic head, alternative pump designs are available that will reduce entrained fish mortality. Investigations are underway on the feasibility and fish protection capability of these alternatives (28).

Most helper systems that involve retention and or processing of the heated discharge will cause 100 percent mortality of entrained biota. Mortality is caused by factors such as increased residence time at elevated temperatures, pressure changes, and stresses in the extra pumps, piping and mechanical equipment required. In cooling towers, toxic chemicals are often added to the flow to control biofouling. Again, mortality or sublethal effects are assured. To offset this, there may be fewer organisms entrained into the intake as a result of attempts to minimize cooling water flows by increasing the temperature rise across the condenser.

In some instances, certain helper system designs may not be feasible due to the expensive land areas required, and the additional capital and operating costs. Many of these systems will also provide minimal or even negative return in decreased biological damage. Based on this assessment, the following criterion is recommended:

Recommendation R116. ***Helper or supplementary cooling systems should not be used on outfalls from once-through cooling systems unless it can be clearly demonstrated that their use will result in decreased total mortality to aquatic organisms entrained in the cooling water and thermal plume.***

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APPENDIX E

RATIONALE FOR RECOMMENDATIONS ON WASTEWATERS (TYPE 2 WATER)

APPENDIX E RATIONALE FOR RECOMMENDATIONS ON WASTEWATER (Type 2 Streams)

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APPENDIX E RATIONALE FOR RECOMMENDATIONS ON WASTEWATERS (TYPE 2 STREAMS)

E.1 Identification and Classification of Type 2 Streams

Service or process water is required for steam generation, equipment cleaning, ash transport, moderator water cooling and domestic uses. Service water is generally withdrawn from the nearest natural water supply together with condenser cooling water. It is then separated from the condenser cooling water flow in the forebay and directed to the various station operations which require it. Where local freshwater quality is unsuitable, service water may be provided by wells or municipal water supplies.

In these codes, service water flows are called "Type 2" streams. As defined in Section 3.1 of the Design Code, these include all station streams to which there is a known or potential addition of a deleterious substance. Measures for their control apply prior to their release to once-through cooling (Type 1) streams, to municipal sewer systems or to local receiving waters.

Type 2 streams include, but are not limited to, the following:

- recirculating condenser and auxiliary cooling water
- once-through auxiliary cooling water discharges that are subject to potential contamination through use in water-to-oil (or other deleterious substance) heat exchangers
- water treatment plant and condensate polisher wastes
- boiler blowdown
- heavy water upgrader wastes
- boiler waterside cleaning wastes
- boiler fireside, air preheater, and stack cleaning wastewaters
- wastewaters from miscellaneous plant and equipment cleaning and decontamination
- radioactive liquid wastes
- leaks and spills of fluids, chemicals and wastewaters
- laboratory wastewaters
- sanitary wastes
- laundry wastes
- roof and yard drain discharges
- fuel storage and handling area wastewaters and runoff

- discharge, runoff and seepage from the collection, transport and disposal of ash, flue-gas desulphurization sludges, radioactive materials and other solid wastes
- any combination of the above streams
- any other station wastewaters not included in the above which meet Type 2 stream specifications.

Figures E.1 and E.2 illustrate typical fossil-fuel and nuclear power station water flow and waste streams.

The sections that follow provide descriptions of the various wastewaters followed by a discussion and recommendations on measures to minimize, contain and/or treat them. Section E.2 describes the following general categories of waste streams in fossil-fuelled (coal, oil or gas) and nuclear generating stations:

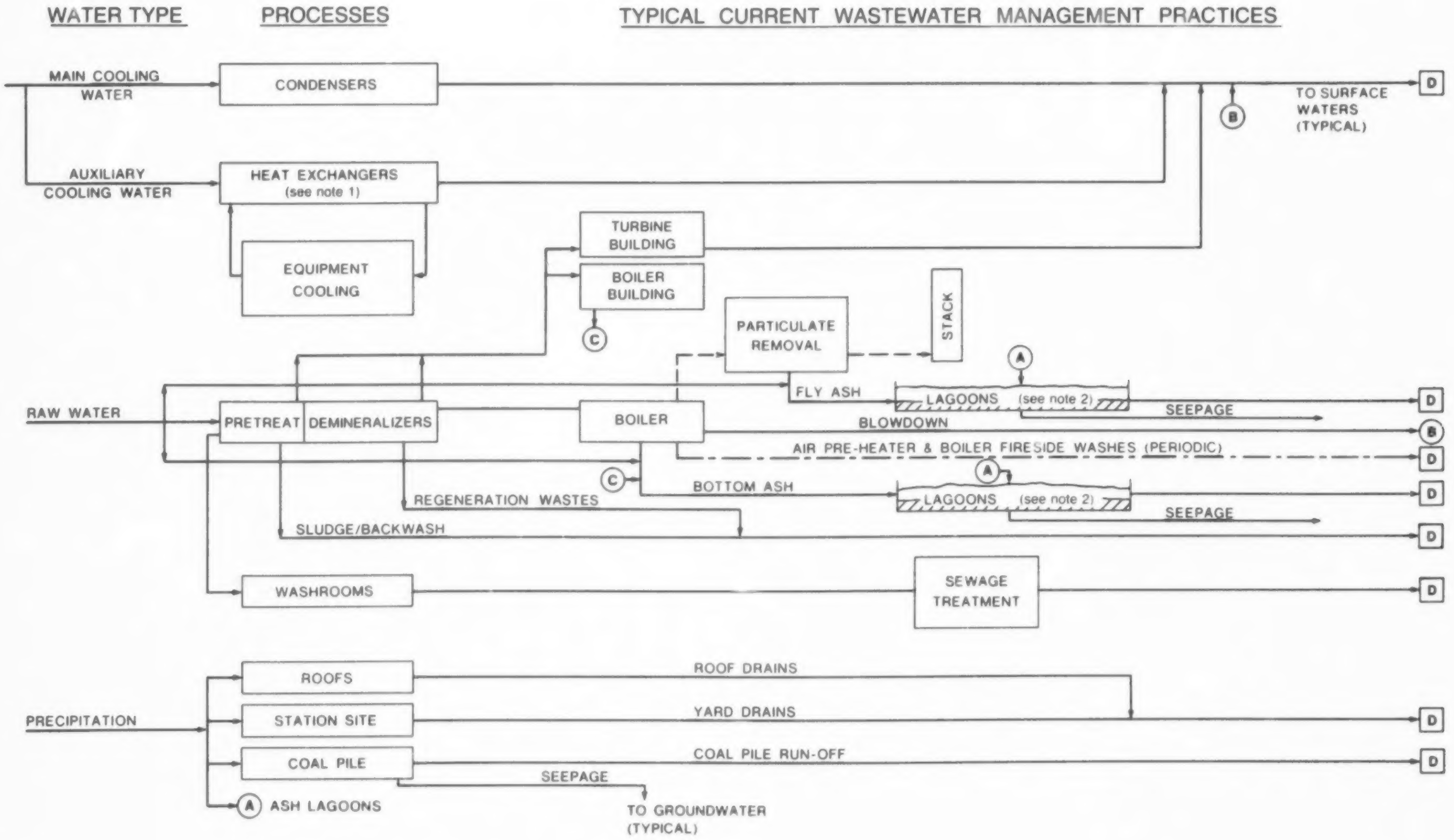
- wastewaters from cooling systems (Section E.2.1),
- wastewaters from in-plant processes (Section E.2.2),
- wastewaters from leaks and spills (Section E.2.3),
- wastewaters generated outside the plant from fuel storage and solid waste disposal (Section E.2.4),
- combinations of waste streams (Section E.2.5).

Waste streams in any of these categories may be common to both fossil-fuelled or nuclear stations or specific to one type of station. The relative volumes of wastewaters for generic 1000-MWe and 2000-MWe stations are illustrated in Figures E.3 and E.4. The derivation of these estimates is discussed is Section E.2.

Sections E.3, E.4 and E.5 discuss the three main approaches that will reduce the environmental impacts of wastewaters and waste residues from steam-electric generating stations. These approaches are:

i) wastewater minimization (E.3),
ii) wastewater containment (E.4), and
iii) wastewater treatment (E.5).

The three approaches are discussed in the logical sequence in which they would be considered and applied in practice. Measures to minimize wastewaters are a fundamental first step that will reduce requirements for both containment and treatment. Effective containment of wastewaters is needed to verify quality prior to release and to facilitate treatment if necessary. In each of the three categories, opportunities to reduce wastewater-related impacts are identified and rationales are provided for technology-


WATER TYPE
PROCESSES
TYPICAL CURRENT WASTEWATER MANAGEMENT PRACTICES
MAIN COOLING WATER
CONDENSERS
TO SURFACE WATERS (TYPICAL)
B
D
AUXILIARY COOLING WATER
HEAT EXCHANGERS (see note 1)
EQUIPMENT COOLING
TURBINE BUILDING
BOILER BUILDING
C
PARTICULATE REMOVAL
STACK
A
RAW WATER
PRETREAT
DEMINERALIZERS
BOILER
FLY ASH
LAGOONS (see note 2)
SEEPAGE
BLOWDOWN
AIR PRE-HEATER & BOILER FIRESIDE WASHES (PERIODIC)
C
BOTTOM ASH
REGENERATION WASTES
SLUDGE/BACKWASH
WASHROOMS
SEWAGE TREATMENT
PRECIPITATION
ROOFS
ROOF DRAINS
STATION SITE
YARD DRAINS
COAL PILE
COAL PILE RUN-OFF
SEEPAGE
TO GROUNDWATER (TYPICAL)
A ASH LAGOONS

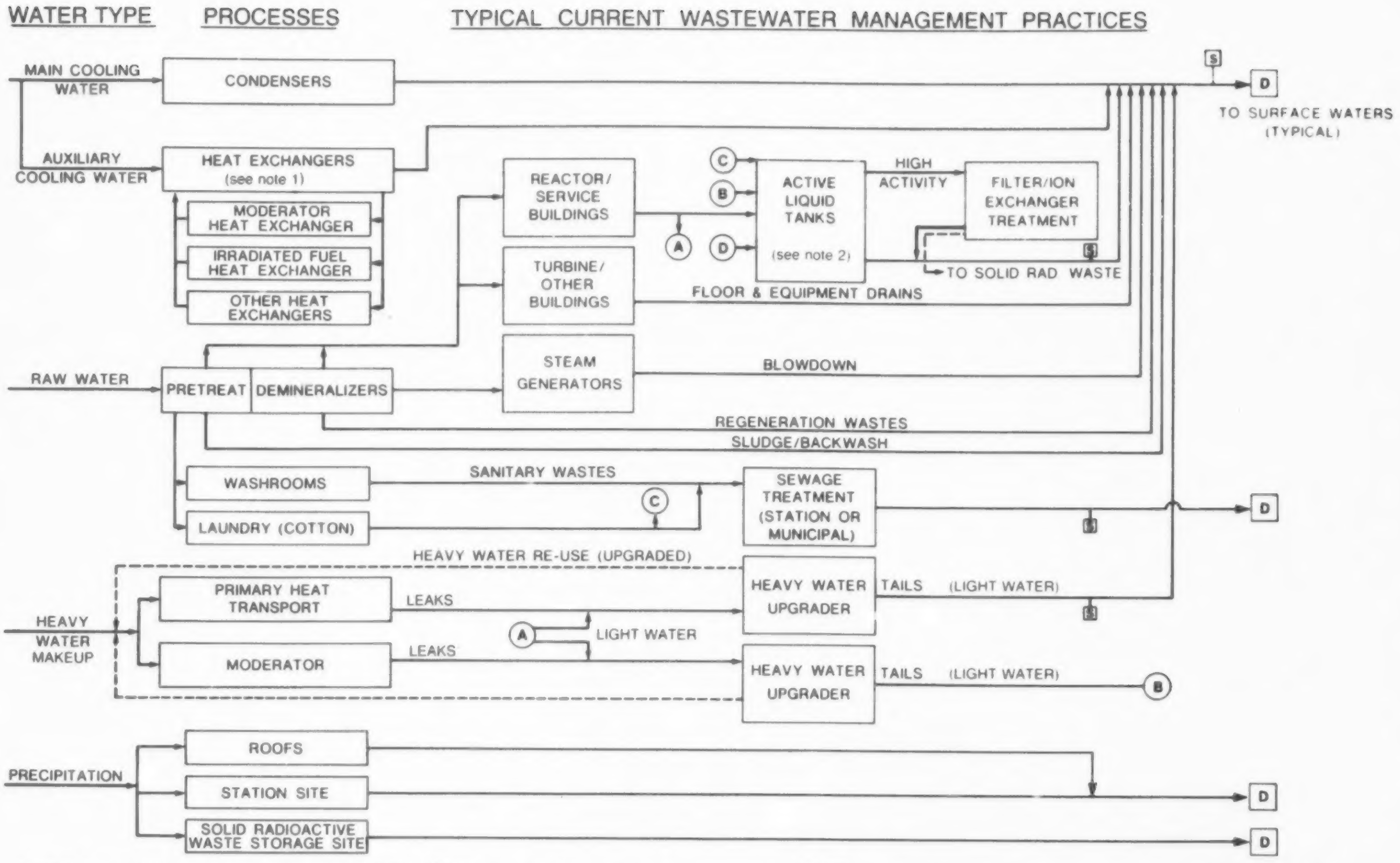
NOTE 1: Direct once-through cooling is commonly used for auxiliary cooling although some recirculating systems are also used as shown. An intermediate recirculating loop is used for seawater services

NOTE 2: Once-through fly ash and bottom transport systems shown are not common in newer plants.

→Ⓐ Ⓐ→ Indicates continuation from a source to a point of discharge

D DISCHARGE

FIGURE E.1 TYPICAL WATER AND WASTEWATER FLOW DIAGRAM - FOSSIL FUELLED GENERATING STATION (Coal)


WATER TYPE
PROCESSES
TYPICAL CURRENT WASTEWATER MANAGEMENT PRACTICES
MAIN COOLING WATER
CONDENSERS
S
D
TO SURFACE WATERS (TYPICAL)
AUXILIARY COOLING WATER
HEAT EXCHANGERS (see note 1)
MODERATOR HEAT EXCHANGER
IRRADIATED FUEL HEAT EXCHANGER
OTHER HEAT EXCHANGERS
REACTOR/ SERVICE BUILDINGS
A
C
B
D
ACTIVE LIQUID TANKS (see note 2)
HIGH ACTIVITY
FILTER/ION EXCHANGER TREATMENT
S
TO SOLID RAD WASTE
TURBINE/ OTHER BUILDINGS
FLOOR & EQUIPMENT DRAINS
STEAM GENERATORS
BLOWDOWN
RAW WATER
PRETREAT
DEMINERALIZERS
REGENERATION WASTES
SLUDGE/BACKWASH
WASHROOMS
SANITARY WASTES
LAUNDRY (COTTON)
C
SEWAGE TREATMENT (STATION OR MUNICIPAL)
S
D
HEAVY WATER RE-USE (UPGRADED)
HEAVY WATER MAKEUP
PRIMARY HEAT TRANSPORT
LEAKS
A
LIGHT WATER
MODERATOR
LEAKS
HEAVY WATER UPGRADER
TAILS (LIGHT WATER)
S
HEAVY WATER UPGRADER
TAILS (LIGHT WATER)
B
PRECIPITATION
ROOFS
STATION SITE
SOLID RADIOACTIVE WASTE STORAGE SITE
D
D

NOTE 1: Some designs utilize a secondary heat exchanger and recirculating cooling loop, as shown, while in others the once-through cooling water is routed directly to the moderator and other heat exchangers.

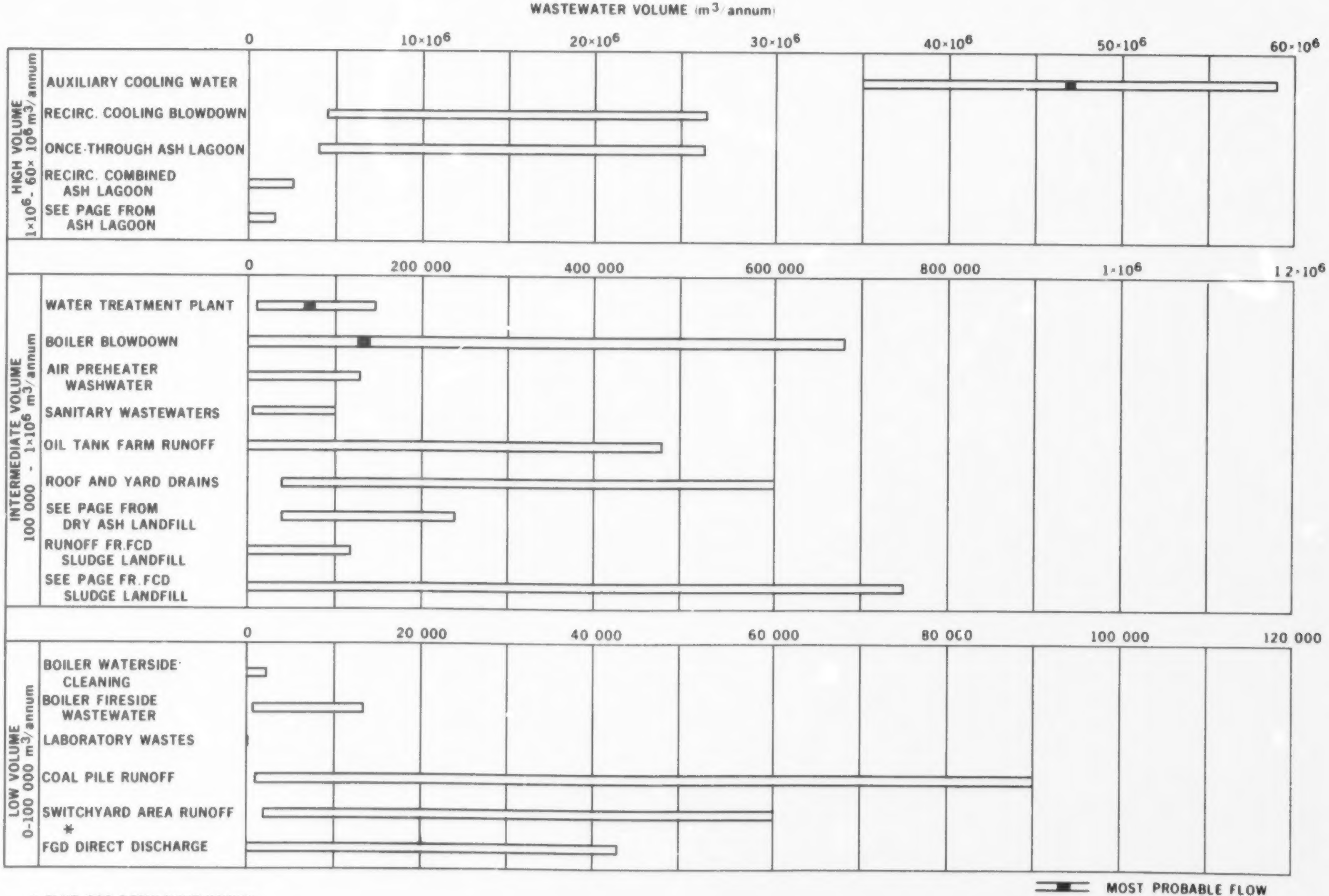
NOTE 2: (D) Wastes to active liquid tanks also include wastes from:
- Decontamination centre
- Plastics laundry
- Fuelling machine shop
- Ion exchange slurry water
- Laboratories (high & low activities)
- Emergency showers, etc.

→(A) (A)→ Indicates continuation from a source to a point of discharge

S SAMPLING AND FLOW MONITORING

D DISCHARGE

FIGURE E.2 TYPICAL WATER AND WASTEWATER FLOW DIAGRAM - CANDU NUCLEAR STATION



* FLUE GAS DESULPHURIZATION

FIGURE E.3 APPROXIMATE ANNUAL WASTEWATER VOLUMES FOR A 1000-MW FOSSIL FUELLED GENERATING STATION

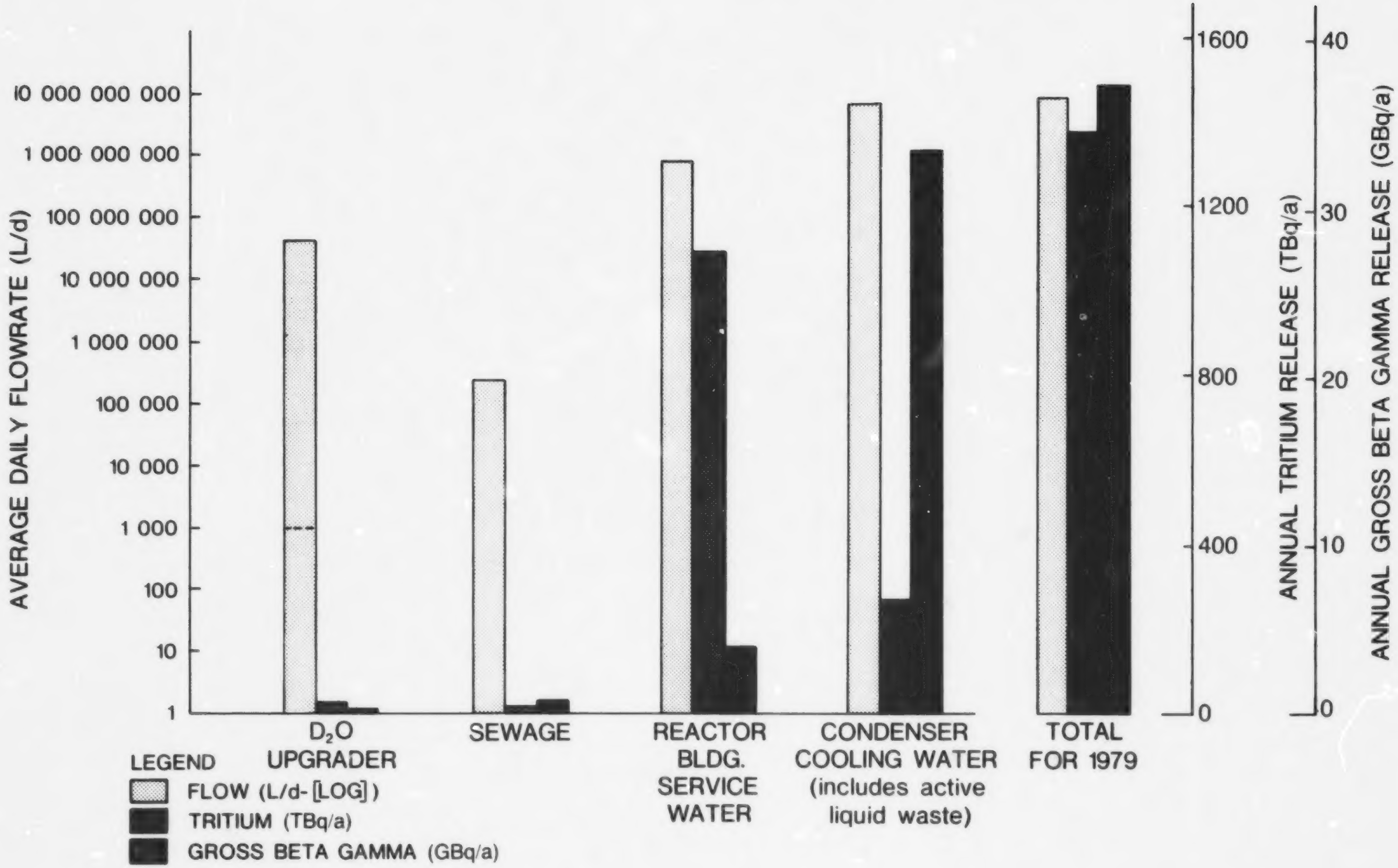


FIGURE E.4 APPROXIMATE ANNUAL WASTEWATER VOLUMES FOR A 2000-MW CANDU NUCLEAR STATION (1)

based recommendations which can be implemented in the designs of new or expanded generating stations.

A fundamental objective in making recommendations for control is not only the reduction in the concentrations of contaminants in wastewaters, but also a reduction in the overall quantities of contaminants that are released over the life of the station, often in relatively high volume, low concentration waste streams.

E.2 Wastewater Sources and Characteristics

E.2.1 Wastewaters from Cooling Systems

(a) Auxiliary Cooling Water Systems. General descriptions and flow requirements for auxiliary cooling systems at steam-electric generating stations are provided in Appendix D.

In addition to the main condensers, generating stations typically contain a large number of small heat exchangers (e.g., oil coolers on pulverizers, bearing coolers on cooling water and boiler feedwater pumps, compressor coolers, turbine lubricating oil heat exchangers, ash hopper cooling, etc.) (2,3,4,5). A nuclear power plant has additional cooling requirements associated with the nuclear reactor systems. The main cooling requirement is for the heavy water circulated to moderate the nuclear reactions. The moderator cooling water heat exchangers are also considered to be an auxiliary cooling system, although their large flow and cooling capacity makes them equivalent in size to the main condensers in smaller fossil-fuelled units. Other cooling services include those associated with reactor end shields, biological shields, fuelling machines, heavy water clean-up, irradiated fuel bay, sampling, and various pumps, including primary heat transport and moderator pumps.

Heat exchangers may be either plate or tube type, with plate type units used primarily for smaller aplications. Although many of the tube type heat exchangers may also be small relative to the main cooling water condensers, some of these may contain several hundreds of tubes, such as that of the Pickering A nuclear station (1400 tubes). The moderator cooling water heat exchangers on each unit of a large nuclear station contain several thousand tubes.

Auxiliary cooling units may be designed with either a single heat exchanger or parallel heat exchangers connected by a closed-loop circuit. These two alternatives are illustrated in Figure E.5. A fluid being cooled, such as lubricating oil or tritiated heavy water, will be on one side of the primary heat exchanger. On the other side of the heat exchanger will be either the once-through cooling water in the case of a single heat

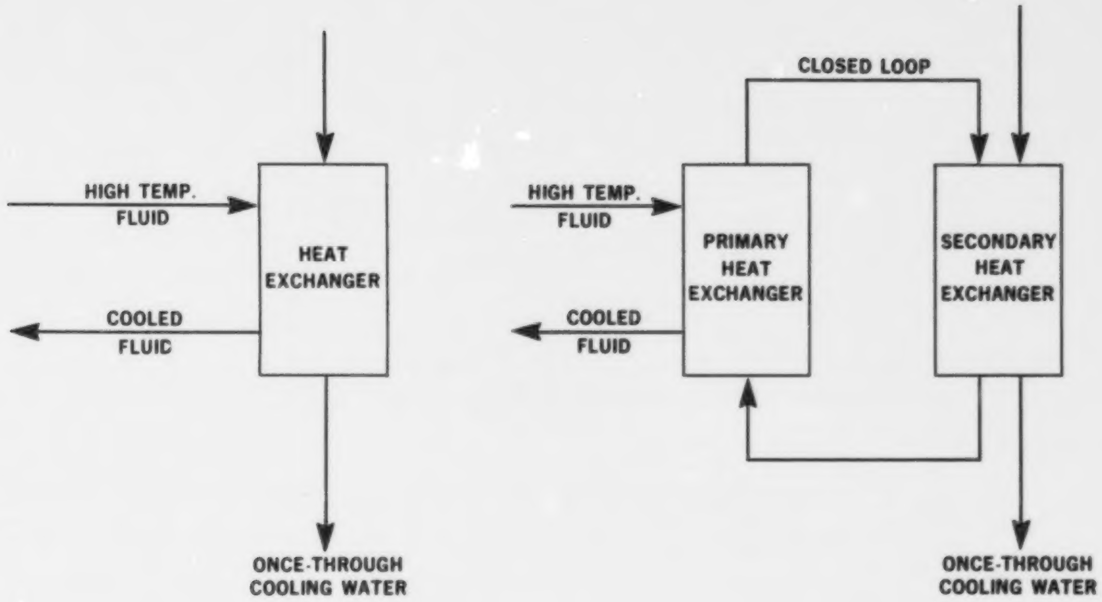

HIGH TEMP. FLUID
HEAT EXCHANGER
COOLED FLUID
ONCE-THROUGH COOLING WATER
CLOSED LOOP
HIGH TEMP. FLUID
PRIMARY HEAT EXCHANGER
SECONDARY HEAT EXCHANGER
COOLED FLUID
ONCE-THROUGH COOLING WATER

FIGURE E.5 SINGLE AND DOUBLE HEAT EXCHANGER ARRANGEMENTS FOR AUXILIARY COOLING

exchanger system, or the secondary loop fluid (usually good quality water treated to minimize corrosion and scaling) in the case of a double heat exchanger system. Both systems are currently used at Canadian generating stations (2,3,5,6).

As indicated in Appendix D, water required for auxiliary cooling will typically be about 5% of the main condenser cooling water flow in a fossil fuelled station, and about 12% in a nuclear station. For a 1000-MW station, once-through auxiliary cooling water flows would be approximately:

- 1500 L/s for a fossil-fuelled station,
- 6900 L/s for a nuclear station.

As defined Appendix C, potentially contaminated auxiliary cooling waters are considered Type 2 (wastewater) streams. Potential contamination depends on whether or not contaminants can enter the stream in the event of a single leak, rupture or spill. When no secondary cooling loop is provided and the pressure on the cooled fluid side is greater than that on the once-through cooling water side of the heat exchanger, a leak or rupture would result in contamination of the once-through cooling water flow stream. Hence, with such systems, the once-through water could be considered a waste stream (Type 2 water).

When a closed secondary loop is provided, a leak of the fluid, oil or heavy water to the closed-loop circuit would result in contamination of the closed-loop water. Although a leak from the closed loop would be considered a Type 2 water, the once-through flow is sufficiently isolated from potential contamination to be considered Type 1 flow.

The primary potential contaminants of once-through auxiliary cooling waters are:

- lubricating oils and sealant fluids (all station types);
- coal ash (coal fuelled stations);
- tritiated heavy water (nuclear stations);
- fission products (nuclear stations).

The concentration of any of these substances in the auxiliary cooling water in the event of a leak is totally dependent on the nature of the leak and the rate of release.

Available data are insufficient to make any generalized estimate of the frequency of heat exchanger leaks, and the rate of release of a contaminating fluid when a leak does occur. However, leaks have been known to occur, such as the heavy water leaks in the moderator heat exchangers at the Pickering A nuclear station in 1979 (7).

(b) Recirculating Condenser Cooling Systems. Currently, once-through cooling systems are the most common systems used for condenser and equipment cooling in Canadian steam-electric generating stations. However, in some situations, recirculating cooling systems are selected for the main cooling requirements for a number of reasons:

- environmental considerations may preclude the water withdrawal or the temperature rise associated with once-through cooling;
- the flow of a river may be restricted at certain times of year due to freeze up or low precipitation;
- for a coal-fuelled station, it may be more economical to site the station at the mine mouth and minimize water use than to transport the coal to a source of once-through cooling water.

The two main types of recirculating cooling systems are cooling ponds and cooling towers. A further classification of these systems is as follows:

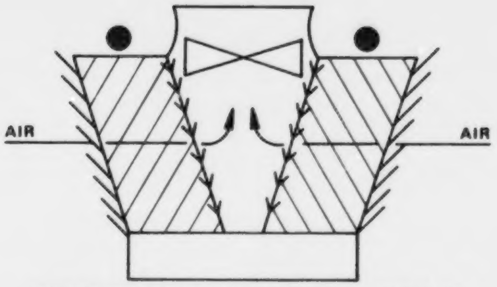
- cooling ponds;
- spray cooling systems - ponds or channels;
- wet cooling towers;
- wet/dry cooling towers;
- dry cooling towers.

Illustrations of these systems are presented in Figure E.6. The most common recirculating cooling systems used by Canadian industries are cooling ponds, wet cooling towers and spray cooling systems, although dry air cooled systems are used in the petrochemical industries for relatively small cooling requirements.

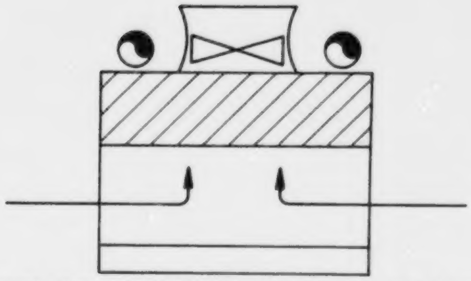
Two recirculating systems in use in Canada at present are mechanical draft cooling towers at the H.R. Milner G.S. and a combination system consisting of a 485 hectare cooling pond supplemented by a spray canal and a mechanical draft cooling tower at the Sundance G.S.. Both of these stations are in Alberta. Recirculating cooling systems are also planned for the Keephills, Genesee and Sheerness stations in Alberta and for the Hat Creek G.S. in British Columbia. Other "semi-recirculating" systems are used at Boundary Dam G.S. (Sask.), Poplar River G.S. (Sask.) and Battle River G.S. At these stations water is recirculated in reservoirs with variable natural flow-through. During extended dry periods these systems would function essentially as closed-cycle systems with controlled blowdown in the form of limited release through the control dams.

The major environmental concerns with recirculating cooling systems are:

- the quality and quantity of wastewater discharges in the form of blowdown from the system (blowdown is required to maintain satisfactory water quality within a recirculating cooling system);
- water intake quantities to make up for evaporation losses, drift losses and blowdown (evaporation and drift losses are greater with wet cooling towers than with cooling ponds);
- the deposition of drift droplets containing concentrations of chemicals (wet cooling towers and spray systems);
- the potential for local fogging and icing problems (more extensive with wet cooling towers than with ponds);
- heated discharges (although smaller than once-through systems);



CROSSFLOW MECHANICAL DRAFT
Cooling Tower **Induced Draft**



COUNTERFLOW MECHANICAL DRAFT
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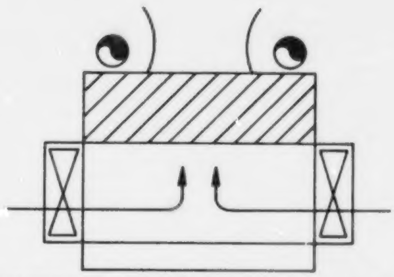

COUNTERFLOW MECHANICAL DRAFT
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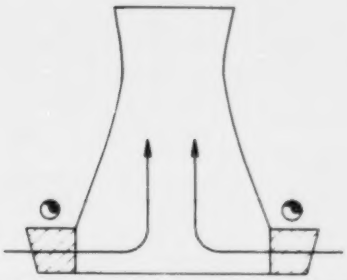
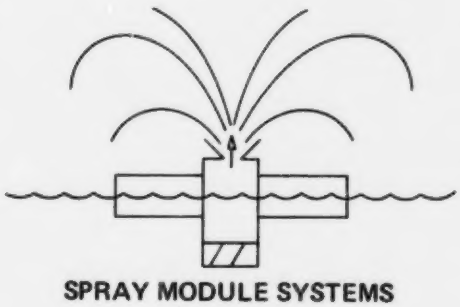
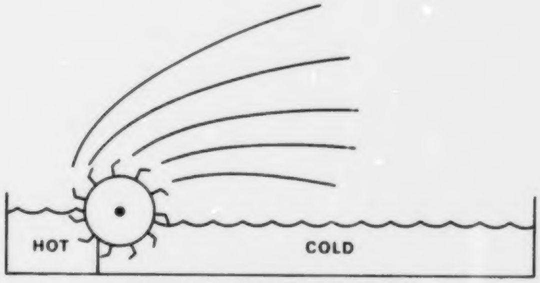


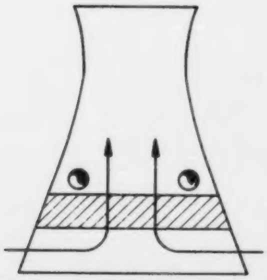
CROSSFLOW NATURAL DRAFT



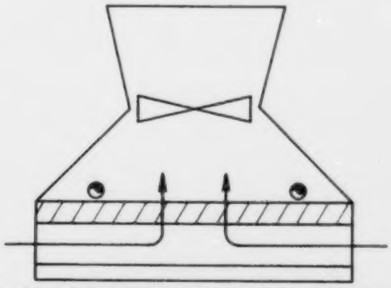
SPRAY MODULE SYSTEMS



SPRAY ROTOR SYSTEM



COUNTERFLOW NATURAL DRAFT



FAN-ASSISTED NATURAL DRAFT
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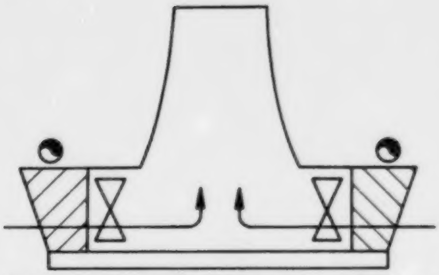
FIGURE E.6 SCHEMATICS OF RECIRCULATING COOLING SYSTEMS (8)



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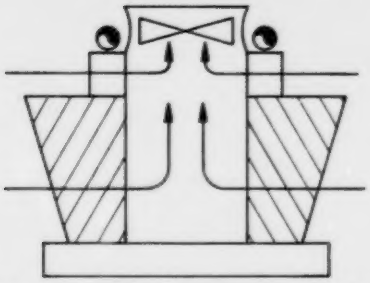

PARALLEL PATH WET/DRY SYSTEM
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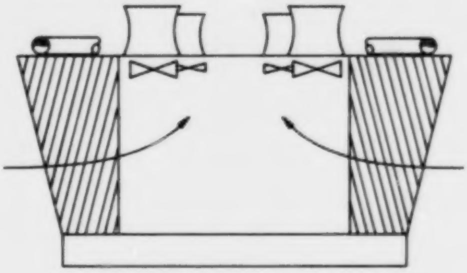

ROUND MECHANICAL DRAFT
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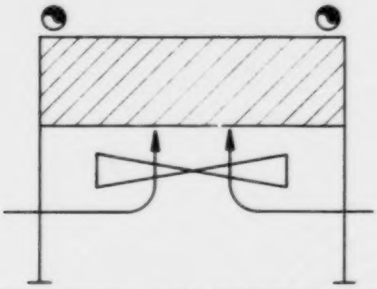

MECHANICAL DRAFT DRY SYSTEM
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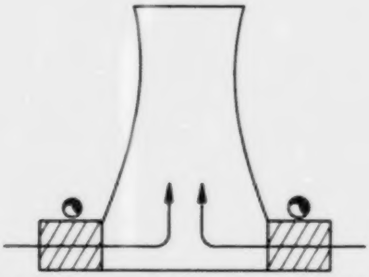
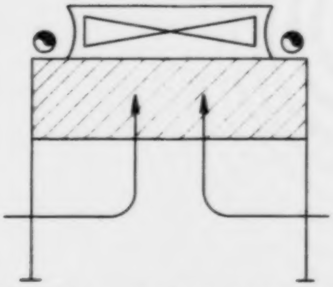


NATURAL DRAFT DRY SYSTEM
Crossflow



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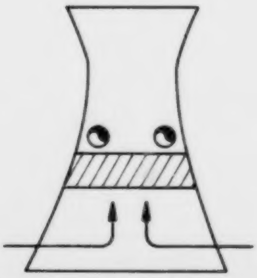
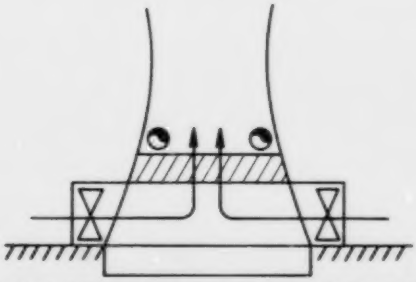


NATURAL DRAFT DRY SYSTEM
Counterflow



FAN-ASSISTED NATURAL DRAFT
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FIGURE E.6 (CONT'D)

- overwintering of migrating waterfowl due to maintenance of ice-free water (applies primarily to cooling ponds);
- land requirements (applies primarily to cooling ponds);
- aesthetics and noise (applies primarily to towers);
- the use of potentially toxic materials of construction (such as asbestos compounds).

From a water pollution standpoint, the blowdown releases from towers and ponds are of greatest concern, followed by the deposition and subsequent non-point source runoff waters that may result from chemically contaminated drift.

Most recirculating water systems are not operated in a totally "closed cycle". A continuous or periodic blowdown from the system is used to maintain a suitable water quality for the satisfactory operation of the system.

Evaporation from the system will cause the concentration of dissolved solids to increase, and this will tend to cause scaling of system components, particularly condenser tubes. Although scaling may also occur in other system components, such as piping, pumps and towers, the scaling of condenser tubes is the most serious because it reduces thermal efficiency. For example, a 1.25-cm rise in condenser back pressure results in approximately a 1% loss in efficiency (9). More importantly, in some instances of relatively inexpensive fuel, condenser scaling may result in the non-availability of a unit (10).

The rate of water intake for and blowdown from a recirculating system depends on the cycles of concentration at which the system is operated. ("Cycles of concentration" is the ratio of chemical concentrations in the cooling water divided by the chemical concentrations in the make-up water.) Increasing the cycles of concentration will increase the tendency to scale, and chemical treatment of the water may be necessary to mitigate this tendency.

The water intake (and discharge) for increasing cycles of concentration in a typical recirculating condenser cooling system is shown in Figure E.7. This is for a wet tower system, and assumes 3% evaporation and drift losses. As the figure indicates, water intake (make-up) and blowdown decrease exponentially with increased cycles of concentration. For example, a tower at a 400-MW fossil station operating at five cycles of concentration, requires make-up at a rate of 263 L/s and has a blowdown rate of 42 L/s, which are 2.5% and 0.4% respectively of the 10 500 L/s circulating water flow (11). Other cooling tower systems operate at higher cycles of concentration (up to 20 cycles).

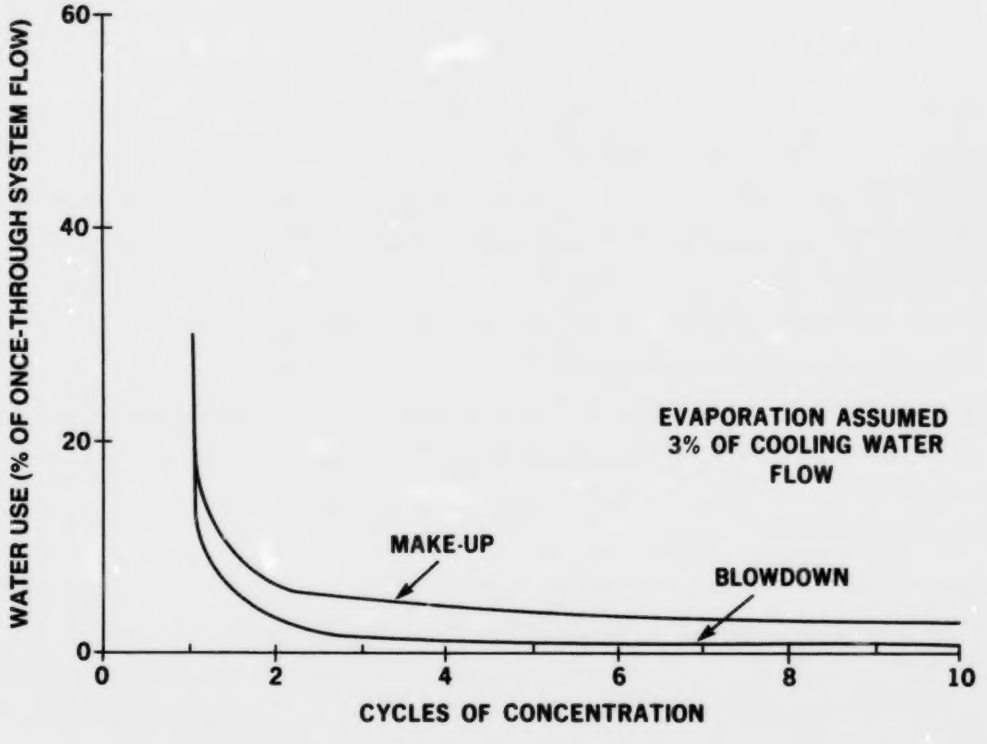


FIGURE E.7 WATER USE AND CYCLES OF CONCENTRATION FOR RECIRCULATING COOLING SYSTEMS

Other recirculating systems, especially cooling ponds, are typically operated at 2 to 2-1/2 cycles of concentration. As Figure E.7 indicates, at these cycles of concentration, intake and blowdown rates would be typically about 6% to 5% and 3% to 2% of a once-through cooling system water intake rate.

At one cooling pond system operating in Canada, the average blowdown rate of 357 L/s prior to installation of a helper tower was about 0.6% of the circulating water flow (12).

Generally, blowdown rates for recirculating cooling systems can be expected to range from about 0.5% to 3% of once-through condenser cooling water flow (11,13). Based on this range, average annual rates and volumes of blowdown for a 1000-MW station are:

	Typical Circ. Water Flow Rates (L/s)	Average Annual Blowdown	
		Rate (L/s)	Volume (m^3/annum)
Fossil fuelled station	28 000	140 - 840	$4.4 \times 10^6 - 26.5 \times 10^6$
Nuclear station	56 000	280 - 1680	$8.8 \times 10^6 - 53.0 \times 10^6$

Blowdown will not only contain high levels of dissolved solids but may also have high suspended solids concentrations and high concentrations of chemicals used to control scaling, corrosion and biological growth. Trace contaminants other than those resulting from chemical additives will not normally be at high enough levels in the blowdown to be of concern in systems operating at two or three cycles of concentration unless they are near concern levels in the make-up water. However, very high levels of dissolved solids may be deleterious and may make the blowdown unsuitable for downstream uses such as agricultural irrigation (14). Each water source will have unique chemistry and may present unique problems of scaling, corrosion and biofouling at high cycles of concentration. Some typical recirculating cooling system blowdown characteristics are presented in Table E.1 (15).

A summary of chemical treatments for various operational problems in recirculating cooling systems is shown in Table E.2, together with the factors and the main causes of these problems. Zinc, chromate and phosphorus compounds are very commonly used, sometimes together as a combined scale/corrosion control treatment (16) and polyelectrolytes are often used to minimize scaling and general fouling. Biofouling control agents may be necessary to maintain clean surfaces in condenser tubes for efficient heat transfer, and also on cooling tower components. Chlorine is the most common chemical used although other biocides may be used.

TABLE E.1 TYPICAL CHEMICAL CHARACTERISTICS OF BLOWDOWN FROM RECIRCULATING COOLING SYSTEMS (15)

	Concentration (µ g/L)	
Pollutant	Intake	Discharge
1,2-Dichlorobenzene	ND	26
2,4-Dichlorophenol	3	8
Pentachlorophenol	-	4
Cadmium, Total	ND <2	5
Chromium, Total	83/20*	55/40*
Copper, Total	12/ND<6*	70/30*
Nickel, Total	ND/ND<5*	ND/10*
Silver, Total	ND <1	2
Total Dissolved Solids	900 000	2 240 000
Total Suspended Solids	2 000	4 000
Total Organic Carbon	22 000	76 000
Boron, Total	500	2 000
Calcium, Total	53 000	140 000
Manganese, Total	8	ND <3
Magnesium, Total	22 000	48 000
Molybdenum, Total	ND <5	40
Phenolics, 4AAP	7	20
Total Residual Chlorine	1 170	0/0/0/0/0
Sodium, Total	170 000	350 000
Tin, Total	ND <5	30
Vanadium, Total	ND <3	10

* These multiple results represent analyses by multiple analytical laboratories.

TABLE E.2 SUMMARY OF CHEMICAL TREATMENTS FOR RECIRCULATING COOLING SYSTEMS (13)

Potential Problem	Factors	Causitive Agents	Chemical Treatments
Scaling	Calcium Alkalinity Temperature pH	Calcium Carbonate Magnesium Silicate Calcium Sulphate Ferric Hydroxide	Acid (e.g. sulphuric) Phosphonates Polyphosphates Polyelectrolytes
Corrosion	pH Aeration Temperature Dissolved Solids Galvanic Couples	Oxygen Carbon Dioxide Chloride	Chromate Zinc Polyphosphate Tannins Lignins Synthetic Organics
Biological Growths	Temperature Nutrients pH Innoculation (from air)	Bacteria Fungi Algae	Chlorine Chlorine Donors Organic Sulphurs Quatenary Ammonia
General Fouling	Suspended Solids Water Velocity Temperature Contaminants Metal Oxides	Silt Oil	Polyelectrolytes Polyacrylates Lignosulphonates Polyphosphates
Wood Deterioration	Microbiology Chemical	Celluloytic Fungi Chlorine Sodium Carbonate	Fungicides Acid

The toxicity of zinc and chromium compounds, particularily hexavalent chromium, is well documented (13, 16). The precipitation of chromium compounds from alkaline cooling waters is of particular concern in cooling ponds. The ultimate disposal of chromium sludges and possible seepage into groundwater are major environmental considerations. Phosphorus compounds can contribute to eutrophication in some receiving waters and excessive amounts of chlorine are toxic to fish.

In fact, chronic toxicities have been reported at TRC (total residual chlorine) concentrations of 0.0015 mg/L for some fresh water species and 0.02 mg/L for some salt water species (17). In Canadian climates it is not expected that biofouling control of cooling towers will be required to the same extent as in warmer climates.

For wood components of cooling towers, fungicides are commonly utilized as preservatives, and these may leach into the cooling water, particularly during the initial commissioning period of the system. However, there is little evidence to indicate that this is a major concern with recirculating cooling systems.

Asbestos cement is used for certain components in some towers such as inlet louvres, tower fill and drift eliminators. Concern with potential fires in wood towers may have influenced this selection. When asbestos-based materials are used, asbestos fibres may be present in circulating water and blowdown as indicated by the data in Table E.3 (15). There is concern about possible toxicity of asbestos materials to fresh water and saltwater organisms, and possible human health hazards.

TABLE E.3 SAMPLES OF COOLING TOWER BLOWDOWN WITH ASBESTOS LEVELS ABOVE DETECTION LIMITS * AT SELECTED U.S. STATIONS (15)

Site No.	Lower Limit of Detection	Make-up Water (fibres/L)	Blowdown (fibres/L)
3	8.4×10^4	B.D.L.**	0.92×10^6
3	8.4×10^4	B.D.L.	110×10^6
4	8.4×10^4	B.D.L.	1.3×10^6
4	8.4×10^4	B.D.L.	160×10^6
9b	1.88×10^6	B.D.L.	37×10^6

* Approximately 10% of the 46 samples taken at 18 sites were above detection limits for asbestos.

** B.D.L. is below detection limit.

A recirculating cooling system blowdown will probably have a higher temperature than the receiving waters. This may cause thermal shock to aquatic species on the initiation and cessation of blowdown, and continuous high temperatures may be lethal to certain species. However, the discharge flows are small in comparison to once-through cooling systems (less than 5%) and with proper outfall design, the impact can be minimized (Sections D.5.4 and D.6.2).

In addition to discharge of chemicals to receiving waters in the system blowdown, the deposition of drift droplets from wet towers on the surrounding area may occur. (Drift is water lost from a tower as liquid entrained in the exhaust, not as evaporation.) This may damage the vegetation in the area and the chemicals may enter receiving waters through runoff.

The chemical composition of drift will be similar to that of untreated blowdown although concentrations may be greater due to the effect of evaporation that takes place as the droplets leave the tower and disperse. With towers using asbestos-based fill materials, asbestos fibres may become airborne with the drift and become susceptible to inhalation.

Fogging and icing may also be associated with wet cooling towers under some hydrometeorological conditions. These considerations may also apply, to a lesser extent, to spray modules in cooling ponds and canals.

E.2.2 Wastewaters from In-Plant Processes

(a) Water Treatment Plant. Boiler water for the steam cycle is normally composed of purified intake water (make-up) plus the returned water from the condensation of steam in the steam cycle. The necessary purification of the make-up water takes place in what is commonly referred to as the "water treatment plant", which is distinct from wastewater treatment facilities.

Since the purification processes employed depend largely on the intake water quality, the number and kinds of processes used may vary from station to station. Commonly used treatment processes include chlorination, dechlorination, physical and chemical clarification, sand and carbon filtration, organic traps and ion exchange. The processes used in a typical water treatment plant are illustrated schematically in Figure E.8. In addition to these processes, lime/lime soda softening, evaporation, reverse osmosis and other treatments may also be used in feedwater treatment. Several Canadian stations use evaporators (12) and one station employs a reverse osmosis system followed by an ion exchange demineralizer (5). The water treatment system components at 19 Canadian stations are summarized in Table E.4 (12).

A condensate polishing treatment (usually ion exchange), which upgrades the condensed water in the steam cycle before it is returned to the boiler, may also be considered part of the boiler feedwater treatment system. Condensate polishing units are used in some Canadian fossil-fuelled power stations but have not been employed to date at Canadian nuclear stations. The condensate polishing facility will usually be located in the turbine house near the condensers.

Components of the feedwater treatment system, such as the flocculation, settling and filtration facilities, may also be used to purify domestic water for drinking fountains, showers, washrooms, cafeterias and/or laundry facilities in the station. If water of acceptable quality is available from wells, adjacent surface waters or municipal

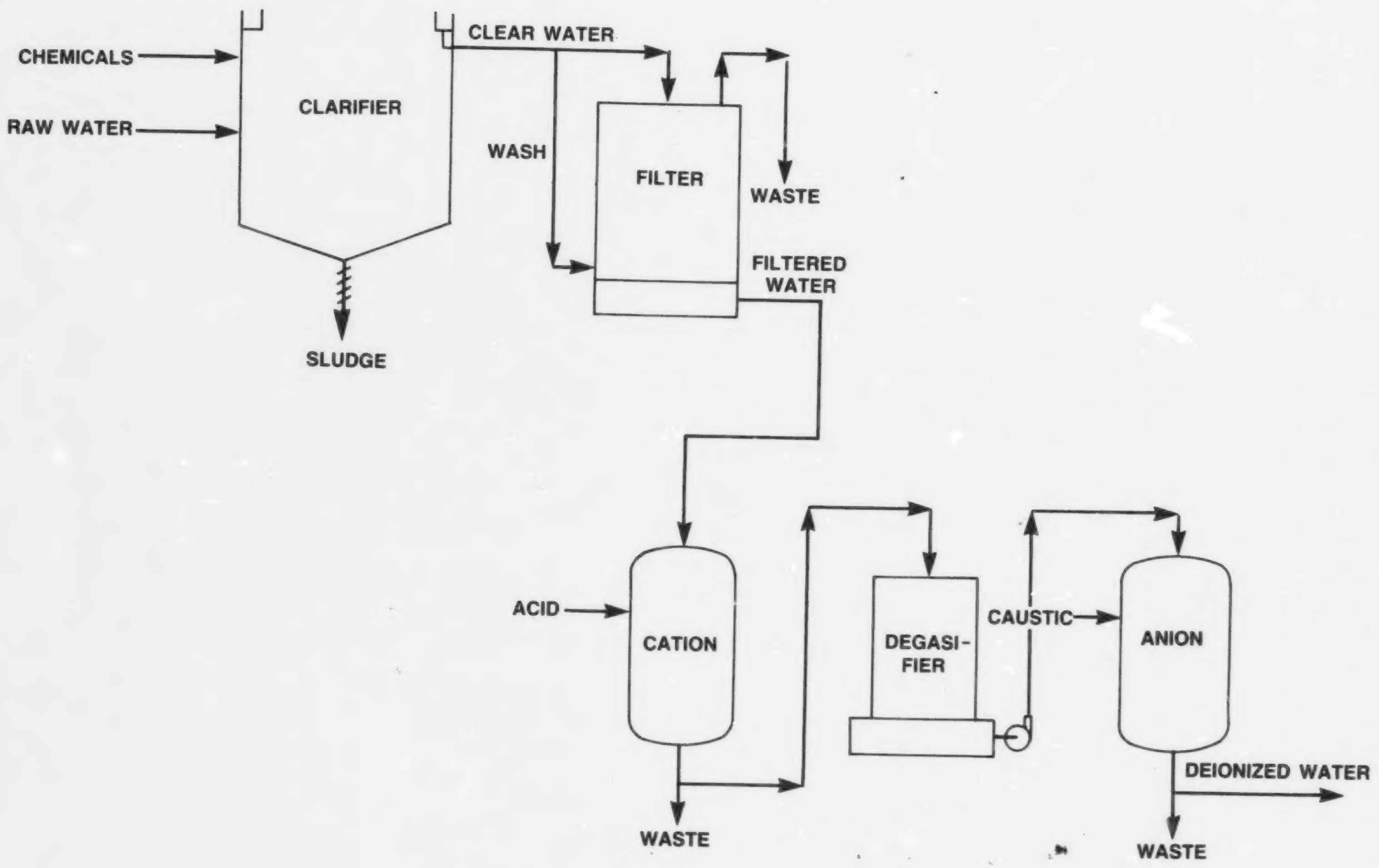

CHEMICALS
RAW WATER
CLARIFIER
SLUDGE
CLEAR WATER
WASH
FILTER
WASTE
FILTERED WATER
ACID
CATION
WASTE
DEGASI-FIER
CAUSTIC
ANION
DEIONIZED WATER
WASTE

FIGURE E.8 SCHEMATIC OF PROCESSES IN A TYPICAL WATER TREATMENT PLANT (18)

TABLE E.4 FEEDWATER TREATMENT AND WASTEWATER QUANTITIES FOR SELECTED GENERATING STATIONS (12)

Station	Capacity (MW)	Treatment	Makeup			Wastewater		
			L/s avg.	m^3/a	$m^3/a \cdot MW$	L/s avg.	m^3/a	$m^3/a \cdot MW$
1105	300	Clar., filt, primary IX, mixed bed IX	3.0	93 490	312	0.30	9 462	32
1306	210	Clar., filt., and ve +-ve IX	2.5	78 730	375	0.71	22 500	107
1307	112	Clar., Cl, +ve and -ve IX, mixed bed IX	94.3	2 975 010	26 560	18.0	367 800	5 070
1310	350	Filt., +ve and -ve IX, mixed bed IX	4.8	150 085	429	1.5	48 300	138
1312	230	Clar., Cl, filt., +ve and -ve IX, mixed bed IX	7.2	227 300	988	6.2	195 500	840
1411	273	Cl, filt., mixed bed IX	8.9	280 500	1 030	0.86	27 000	99
1413	110	Clar., filt., and IX	3.1	98 190	893	0.51	16 110	146
2104	600	Clar., lime soft., filt., +ve and -ve IX, mixed bed IX						
3104	1 200	Org. trap, soft., degas., mixed bed IX	10.3	325 000	271	1.2	37 850	32
3106	100	Filt., org. trap, mixed bed IX	0.54	17 000	170	0.03	1 022	10
3109	4 000	Clar., filt., multi-tank IX	23.9	753 000	188	3.2	100 000	25
3110	2 000	React., filters, +ve and -ve IX, degas, mixed bed IX	18.9	595 000	298	7.9	250 000	125
3209	2 000	Cl, clar., lime soft., filt., + ve and mixed bed IX	17.1	540 000	2170	3.2	100 000	50
4104	156	Lime soft., mixed bed IX	1.0	30 600	196	0.45	14 320	92
4203	65	Na Soft., evap.	0.03	1 000	15	0.03	805	12
4328	66	Clarifier, lime and ycolite soft., deaeration	982.5	31 000 000	469 700	85.6	2 700 000	40 910
4330	1 350	Lime sof., evap., IX (+ve, -ve and mixed bed)	27.3	860 000	637	2.4	76 000	56
4331	660	Mixed bed IX	0.79	25 000	38	0.22	7 000	11

Legend

clar. - clarifier
filt. - filter
cl - chlorine
+ve IX- cation excanger
-ve IX - cation exchanger
mixed bed IX
org. trap- organic trap
soft. - softener
degas - degasifier
evap. - evaporator

water supplies, drinking water treatment facilities may not be required at the station. However, if water quality is not adequate for domestic uses then domestic water treatment is required. Treatment of water for domestic use may include flocculation with alum, lime or ferric sulphate followed by settling, filtration and, possibly, chlorination.

The wastes associated with feedwater treatment consist of concentrated solutions or sludges of the removed chemicals plus the chemicals or residues added for the purification steps employed.

The sludge from clarifiers, which may include coagulant chemicals as well as the settled solids, is typically removed in the form of a water slurry or sludge. The carryover particles retained on the filters downstream of the clarifier are removed periodically by backwashing the filters, which creates some additional wastewater. However, this backwash water can be recycled to the clarifier to reduce wastewater volumes. Wastewaters from ion exchange systems result from the periodic backwashing of solids from the resin beds (usually by reversing the flow through the bed); the rinsing regeneration chemicals from the beds after regeneration (which is typically accomplished by passing the regenerant solution through the bed at a controlled flow rate for a certain period of time); and disposal of the spent regenerant solution(consisting of the chemical used and ions of solids removed from the bed). Wastewaters from reverse osmosis (RO) systems will consist of a RO reject or brine stream (5,15). Evaporators operate with a blowdown (a portion of the boiling water) that is similar in chemical composition to the raw water but with a much higher solids concentration (18).

Table E.4 (12) indicates that the total wastewaters generated from water treatment at stations that do not produce non-electric process steam range from 10 to 146 $m^3/a \cdot MW$, with a median of approximately 75 $m^3/a \cdot MW$. For a 1000 MW station, this converts to a range of from 10 000 to 146 000 m^3/a with a median of about 75 000 m^3/a. The variations in quantities produced depend on the combination of processes used and the intake water quality. Stations that treat water for the production of non-electric process steam have much larger volumes of make-up and wastewater, with wastewater quantities ranging from 850 to 40 910 $m^3/a \cdot MW$. However, these large volumes should not be attributed to electric power generation but to the end process (e.g., heavy water production).

Since complete data were not available for nuclear stations in operation, Table E.4 contains only data from fossil-fuelled stations. It is not known how the wastewater quantities from water treatment at nuclear stations compare with those from fossil-fuelled stations, although partial data suggest that the water treatment plant make-up at nuclear stations may be considerably higher (12).

For further reference, Table E.5 lists wastewater flow rates per megawatt for several individual treatment processes in coal-fuelled generating stations in the United States (15).

TABLE E.5 WASTEWATER FLOW RATES PER MW FOR SEVERAL FEEDWATER TREATMENTS (15)

Treatment	Number of Stations	Flowrate (L/d•MW) Range	Flowrate (L/d•MW) Mean
Clarifier Blowdown	87	0.15 - 4572	245
Filter Backwash	154	0.05 - 9085	269
Ion Exchange Softener Spent Regenerant	104	0.45 - 7677	79
Lime Softener Blowdown	37	1.05 - 2366	212
Reverse Osmosis Brine	3	0.95 - 348	117

The quality of wastewaters from a water treatment plant will depend on the individual processes and chemicals used. Table E.6 lists some of the common chemicals added to aid coagulation/flocculation in clarifiers and Table E.7 indicates common ion exchange material types and reagent requirements for bed regeneration.

Table E.8 (18) lists typical concentrations of some constituents in wastewaters from clarifiers, ion exchange systems and evaporators. In general, the characteristics of primary concern in water treatment plant wastewaters are pH, total suspended solids (TSS) and total dissolved solids (TDS). Clarifier wastewaters tend to be fairly neutral with high TSS. Ion exchange wastewaters are usually acidic or alkaline with a high TDS component. Evaporator wastewaters tend to be alkaline with a high TDS component. Evaporator wastewaters tend to be alkaline with a TDS concentration 3 to 5 times that in the make-up water (18).

In addition to treatment of boiler feedwater to remove solids, various chemical additions are also commonly made after treatment. For example, chemicals may be added to maintain optimum pH, scavenge oxygen, and in general, to prevent,

TABLE E.6 COAGULATING AND FLOCCULATING AGENT CHARACTERISTICS (15)

Coagulant/Flocculant	Purpose	Normal Dosage (mg/L)
Alum	Main Coagulant	5 - 50
$Al_2 (So_4)_3 \cdot 14\ H_2O$	To assist coagulation	2 - 20
Aluminate	Main Coagulant	5 - 15
$Na_2AL_2O_4$	To assist coagulation with alum	(0.1 to 0.5 of alum dosage)
Ferric Chloride $FeCl_3 \cdot 6H_2O$	Main coagulant	5 - 50
Copperas $FeSO_4 \cdot 7\ H_2O$	Main coagulant	5 - 50
Weighting Agents (bentonite, Kaolin, montmorillonite)	Coagulant Aid	-
Adsorbents (powdered carbon, activated alumina)	Coagulant Aid	-
Polyelectrolytes (inorganic activated silica and organic polymers)	Coagulant Aid	2

minimize or delay various chemical reactions in the steam cycle which may adversely affect the heat exchange surface. These are discussed further in the following section on boiler blowdown.

(b) Boiler Blowdown. After treatment and chemical addition, the boiler feedwater enters the boiler. However, the continual recycling through boiler, turbine and condenser eventually results in the build-up of impurities in the water. This may cause scaling and/or corrosion of the boiler evaporative surfaces. Boiler scaling will occur even with relatively low solids concentrations due to the reduced solubility of solids at the high temperatures experienced in the boiler. Scaling may result from the decomposition by heat of calcium bicarbonate to calcium carbonate and carbon dioxide, or by deposition of silica or oxides of iron and copper, which have been corroded from metal surfaces of steam-cycle equipment. The corrosion results from the presence of dissolved oxygen and carbon dioxide in the boiler water (18) and other mechanisms.

Boiler water quality is often maintained by condensate polishing, addition of chemicals to inhibit scaling and corrosion, and blowdown of a portion of the water from

TABLE E.7 ION EXCHANGE MATERIAL TYPES AND REGENERANT REQUIREMENTS (15)

Regenerant Ion Exchange Material	Description Operation	Regenerant Solution	Requirement Theoretical Amount
Cation Exchange Sodium Cycle	Sodium cycle ion exchange is used as a water softening process. Calcium, magnesium, and other divalent cations are exchanged for more soluble sodium cations.	10% brine NaCl solution or some solution with a relatively high sodium content such as sea water.	-
Hydrogen Cycle Weak Acid	Weak acid ion exchange removes cations from water in quantities equivalent to the total alkalinity present in the water.	H_2SO_4 or HCl solution with acid strength as low as 0.5%	110-120%
Strong Acid	Strong acid ion exchange removes cations of all soluble salts in water.	H_2SO_4 or HCl solution with acid strength ranging from 2.0-6.0%	200-400%
Anion Exchange	Weak base ion exchange removes anions of all strong mineral acids (H_2SO_2, HCl, HNO_3, etc).	NaOH, NH_4, Na_2CO_3 solutions of variable strength.	120-140%
Strong Base	Strong base ion exchange removes anions of all soluble salts in water.	NaOH solutions at approximate 4.0%	150-300%

TABLE E.8 CONCENTRATIONS OF SELECTED PARAMETERS IN WATER TREATMENT WASTEWATERS (18)

Parameter	Concentration (mg/L)	
	Mean	Std. Dev.
Clarifier Wastewater		
Total Suspended Solids (TSS)	25 210	53 060
Total Hardness (as $CaCO_3$)	3 220	7 810
Iron (Fe)	352	572
Ion Exchange Wastewater		
Total Dissolved Solids (TDS)	7 410	11 550
Sulphate (SO_4)	2 080	3 860
Chloride (Cl)	1 710	4 600
Sodium (Na)	3 110	6 450
Ammonia (NH_3)	46	137
Evaporator Blowdown		
Total Dissolved Solids (TDS)	730	800
Total Suspended Solids (TSS)	175	440
Sulphate (SO_4)	79	108
Chloride	194	337

the steam cycle. As well as removing some water of deteriorated quality, boiler blowdown helps maintain quality by removing small quantities of sludge produced by the chemicals added as precipitating, chelating or complexing agents. The water blowdown is replaced by an equivalent quantity of high quality water from the water treatment plant.

Table E.9 lists boiler blowdown quantities for selected Canadian fossil-fuelled and nuclear generating stations (12). The data presented show that blowdown varies from less than 1 $m^3/a \cdot MW$ to 683 $m^3/a \cdot MW$, with a mean value of 134 $m^3/a \cdot MW$ (excluding the station with 4 545 $m^3/a \cdot MW$, which generates substantial quantities of process steam). This compares closely with the following blowdown rates reported for fossil-fuelled stations in the United States (15):

Stations	Blowdown Rate ($m^3/a{\cdot}MW$)
230 Coal-Fuelled	204
148 Oil-Fuelled	105
189 Gas Fuelled	59

Using 1, 134 and 683 $m^3/a{\cdot}MW$ as representative of low, mean and high rates, boiler blowdown from a 1 000 MW station would range from 1 000 to 683 000 m^3/a, with a mean value of about 134 000 $m^3/a{\cdot}MW$.

The high variability in blowdown rates may be caused by several factors including make-up water quality after initial treatment, use or non-use of condensate polishing (common in fossil-fuelled stations but not used to date in CANDU nuclear stations), and extent of chemical addition to control scaling and corrosion. The blowdown rate will normally be higher during boiler or steam generator start-up than during normal operation.

The boiler blowdown is generally low in total impurities compared to other station wastewater streams and even compared to many raw intake waters. However, its chemical impurities may differ from raw intake waters both in chemical species content and the respective concentrations of the common species. Also, the oxygen content of blowdown tends to be very low. It may contain residues of oxygen scavenging chemicals (e.g., hydrazine) as well as residues of other anti-corrosion or anti-scale deposition products, corrosion products from the system heat transfer surfaces and scale forming substances which have been concentrated during recycling.

Table E.9 (12) lists chemical additives used at selected Canadian generating stations and Table E.10 (15) identifies the purpose of a number of commonly used additives. All Canadian stations listed in Table E.9 use hydrazine (H_2NNH_2) to maintain a low oxygen level. Most use either morpholine ($OCH_2CH_2NHCH_2CH_2$) or ammonia for pH control and sodium phosphate for scale control.

Except for phosphate and silicate concentrations, available blowdown quality data are very limited. Phosphate concentrations reported at 20 Canadian stations ranged from negligible to 35 mg/L, with a mean value of 14 mg/L (12). Data on Cu and Fe, the metals most likely to result from corrosion in the boiler, are available for 2 stations only:

Station	Concentration (mg/L) Cu	Fe
1407	1.0	1.0
1413	0.02	0.02

Data on stations in the United States show the following average concentrations for selected parameters in boiler blowdown (15):

Pollutants	Number of Samples	Mean Concentration (mg/L)	Standard Deviation (mg/L)
Copper	258	0.14	0.9
Iron	273	0.532	0.06
Oil & Grease	151	1.74	4.53
Phosphorus	19	17.07	12.52
Suspended Solids	230	66.26	500.40

(c) Heavy Water Upgrader Wastewaters. In CANDU stations, due to the expense of heavy water (currently \$250 -\$300/kg), care is taken to conserve the heavy water inventory. The heavy water inventory for an existing four-unit 2 000 MW(e) station is 1 000 000 litres for the moderator and 680 000 litres for the primary heat transport. Extensive efforts are made to minimize heavy water leaks and spills, to segregate and collect these leaks, and to recover and re-use the heavy water in these "wastewaters". Drains associated with the moderator and primary heat transport systems are collected, and if the deuterium oxide isotopic content is greater than 0.5 percent by weight, it is upgraded (1).

Typical heavy water clean-up and upgrader systems are presented in Figure E.9. They consist of distillation columns preceded by a filter/ion exchanger. The separation of heavy water from light water is based on the difference in their boiling temperatures in the distillation columns. An upgrader system can increase the deuterium content to 99.8% percent by weight isotopic deuterium oxide.

TABLE E.9 BOILER WATER ADDITIVES AND BOILER BLOWDOWN QUANTITIES FOR SELECTED STATIONS (12)

Station	Capacity (MW)	Chemical Additives	Boiler Blowdown			Periodic or Continuous
			L/s avg.	m^3/a	$m^3/a{\cdot}MW$	
1105	300	Trisodium Phosphate, Hydrazine, Morpholine	(Not Available)			Per.
1306	210	Sodium Phos., Sodium Sulphite, Hydrazine, Ammonia	0.03	795	3.8	Per. and Cont.
1307*	112	Sodium Phos., Sodium Sulphite, NaOH, Hydrazine Ammonia	0.06	1 900	17.0	Per.
1312*	230	NaOH, Hydrazine, Ammonia	0.04	1 200	5.2	Per.
1411	273	Tri-Na Phos., Di-Na Phos., NaOH, Hydrazine, Ammonia Morpholine, Cyclohexylamine	5.8	182 000	667	Per.
1413	110	Tri-Na Phos., Di-Na Phos., Hydrazine, Filming Ammonia	0.02	786	7.1	Cont.
1414	1 050	Hydrazine, Ammonia	0.003	100	0.1	Per.
1415**	680	Tri-Na Phos., Hydrazine, Ammonia	0.22	7 000	10.3	Cont.
2104	600	Tri-Na Phos., di-Na Phos., Hydrazine Morpholine	1.1	35 000	58.3	Per.
3106	100	Hydrazine, Morpholine	0.01	450	4.5	Per.
3111*	2 928	Hydraznie, Morpholine	63.4	2 000 000	683	Cont.
4104	156	Na Hexametaphos., Tri-Na Phos., Na Sulphite, NaOH, Hydrazine	0.04	1 137	7.3	Per.
4305	405	1,2,3-Na Phos., Na sulphite, Na OH, Hydrazine	1.6	50 000	123	(?)
4317	362	Hydrazine, Chexylamine	1.9	59 730	165	Cont.
4328*	66	Hexametaphos., Cu Sulphate	9.5	300 000	4545	Per. and Cont.
4330	1 350	Hydrazine, Ammonia Hydroxide	10.4	330 000	244	Per
4331	660	1,2,3 Na Phos., Hydrazine, Morpholine, Ammonian Hydroxide	0.32	10 000	15.1	(?)

* These stations produce non-electrical process steam that is not recycled.

** Under construction; additives and quantities estimated.

TABLE E.10 CHEMICAL ADDITIVES COMMONLY ASSOCIATED WITH INTERNAL BOILER TREATMENT (15)

Control Objective	Candidate Chemical Additives	Residual Concentration in boiler Water
Scale	di- and tri-sodium phosphates	3-60 mg/L as PO_4^-
	Ethylene diaminotetracetic acid (EDTA)	20-100 mg/L
	Nitrilotriacetic acid (NTA)	10-60 mg/L
	Alginates Polyacrylates Polymethacrylates	up to 500-100 mg/L
Corrosion	Sodium sulphite and catalyzed Sodium sulphite	less than 200 mg/L
	Hydrazine Morpholine	5-45 mg/L
pH	Sodium hydroxide Sodium carbonate Ammonia Morpholine Hydrazine	added to adjust boiler water pH to the desired level, typically 8.0 - 11.0
Solids Deposition	Tannins Lignin derivatives	$\leq$200 mg/L
	Starch Alginates Polyacrylamides Polyacrylates Polymethacrylates Phosphates	20-50 mg/L

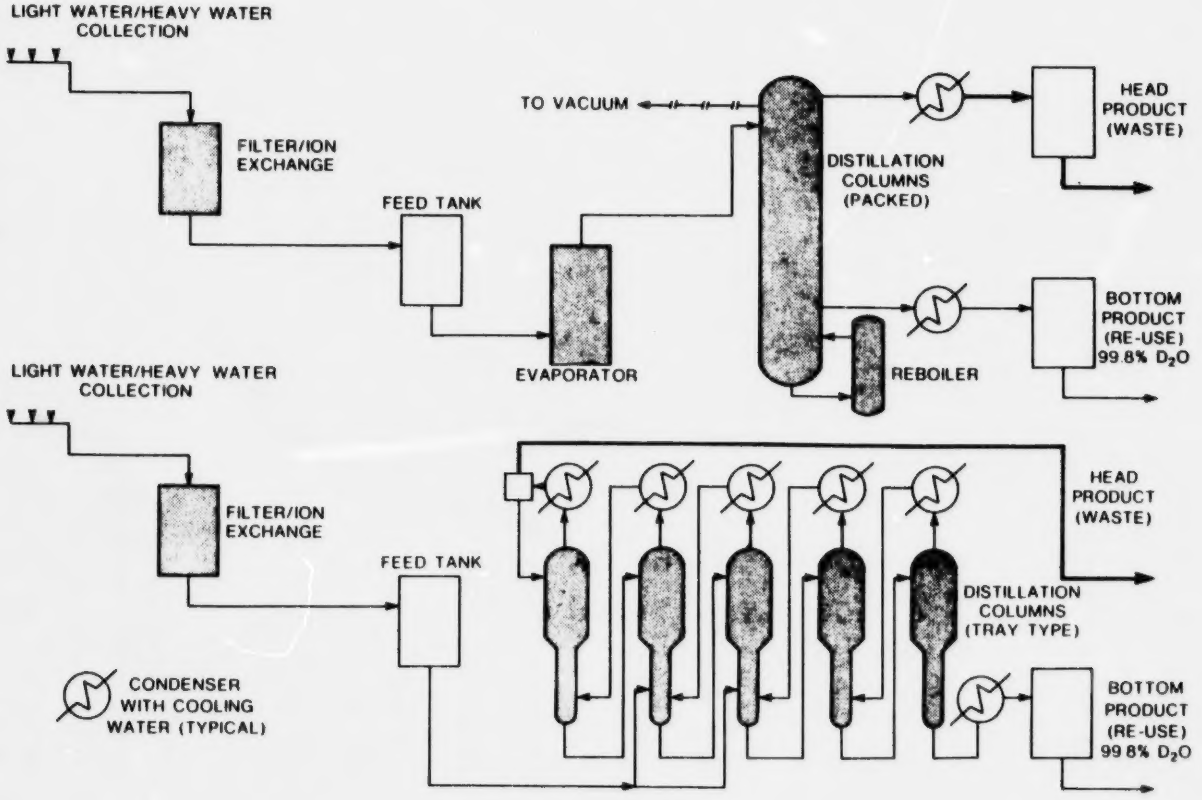

LIGHT WATER/HEAVY WATER COLLECTION
FILTER/ION EXCHANGE
FEED TANK
EVAPORATOR
TO VACUUM
DISTILLATION COLUMNS (PACKED)
REBOILER
HEAD PRODUCT (WASTE)
BOTTOM PRODUCT (RE-USE) 99.8% D_2O
LIGHT WATER/HEAVY WATER COLLECTION
FILTER/ION EXCHANGE
FEED TANK
HEAD PRODUCT (WASTE)
DISTILLATION COLUMNS (TRAY TYPE)
BOTTOM PRODUCT (RE-USE) 99.8% D_2O
CONDENSER WITH COOLING WATER (TYPICAL)

FIGURE E.9 HEAVY WATER CLEAN-UP AND UPGRADER SYSTEM FOR PRIMARY HEAT TRANSPORT AND MODERATOR HEAVY WATER (1)

Usually one heavy water upgrader system is dedicated to the moderator system and another system is dedicated to the primary heat transport system and various sumps in the reactor building. The recovered heavy water is recycled to the moderator or primary heat transport system and various sumps in the reactor building. The recovered heavy water is recycled to the moderator or primary heat transport systems from their respective upgraders after cooling, while the "head product" or "tailings" are discarded as wastewater streams.

The moderator upgrader tailings are typically routed to the active liquid waste system (see E.2.5) while the tailings from the primary heat transport upgrader are discharged directly from the station.

Data for primary heat transport tailings are presented in Table E.11. These data are based on Pickering 1979 information (1).

TABLE E.11 TYPICAL HEAVY WATER UPGRADER TAILINGS DATA, PRIMARY HEAT TRANSPORT SYSTEM (Pickering 1979) (1)*

Flow Rate (average)	950 L/d
Activity (average)	
Tritium	48.15 MBq/L
Gross Beta-Gamma	41 Bq/L

* Calculated on the basis of 17.26 TBq/annum tritium and 13.78 MBq/annum gross beta-gamma.

The characteristics of the tailings will vary depending on the feed conditions to the upgrader plant. This stream will contain some tritium (which was associated with the heavy water) but will be chemically a high quality water due to the filtration/ion exchange steps in the upgrading process.

(d) Boiler Waterside and Condenser Cleaning. Boiler waterside cleaning includes the cleaning of the internal boiler surfaces and accessory equipment surfaces which are in contact with the boiler water in its liquid or vapour phases in the steam power cycle. There are two types of cleaning: pre-operational and operational.

Pre-operational cleaning is a one-time operation prior to start-up. It is carried out to remove an iron oxide scale which forms on metal surfaces during the manufacture and assembly of boiler steel components. Also any oil, grease or construction debris remaining in the steam path after assembly is removed (18). Pre-operational cleaning will typically consist of these steps:

- alkaline boilout followed by drain and rinse,
- acid clean followed by drain and rinse,
- alkaline boilout to neutralize trapped acid, and
- passivation rinse.

Operational boiler cleaning may be required periodically during operation to prevent or remove corrosion and/or scaling to maintain the heat exchange surface efficiencies. Cleaning is normally accomplished by washing or soaking the surfaces with cleaning solutions which are formulated for particular boiler problems. These are usually proprietary chemicals. Commonly used cleaning solutions include both acid and alkaline solutions which may also contain one or more special additives such as oxidizing agents, chelating or complexing agents and metal surface pacifiers. The number of solutions used generally ranges from one to four. These may be interspersed with or followed by water rinses to remove the chemical residues left by the treatment. The solutions employed and their sequence depends largely on the nature of the deposits and/or corrosion and the materials used in the boiler. However, several different kinds of treatment with slightly different properties may be used to treat essentially the same basic problems in different stations. For example, an alkaline solution containing an oxidizing agent may be used for copper removal prior to acid cleaning or an acid cleaning solution which contains a metal complexing agent may be employed alone.

Pre-operational cleaning of the steamside of condensers is usually performed with alkaline solutions (18) and post-operational cleaning is seldom required. Operational cleaning of the condenser cooling water side is practiced at only a few stations in Canada, and usually not more than once a year. Several stations use mechanical cleaning methods (e.g., nylon brushes and water gun), while two stations use a commercial soap or cleaning agent soak and flush procedure (12). Acid cleaning or mechanical cleaning devices will become more prevalent with increasing use of cooling towers (10).

The quantities of wastewater produced from either a pre-operational or an operational boiler waterside cleaning depend on the size and number of boilers, and the number of stages in the cleaning process. While all boilers undergo a pre-operational cleaning, operational boiler waterside cleaning is carried out at less than half the fossil-fuelled stations in Canada and had not been performed to 1977 on steam generators at any CANDU nuclear stations (12).

Tables E.12a and E.12b indicate the volumes of wastewaters produced by four-step and six-step cleaning procedures on a 500-MW boiler (19). This suggests that wastewater volumes for a 1000 MW installation would be:

Pre-operational cleaning	1800-2250 m^3 (one time)
Operational cleaning	0 (no cleaning) 1800-2250 m^3/a (once per year cleaning)

TABLE E.12a AVERAGE CHARACTERISTICS OF BOILER CLEANING WASTES FROM A FOUR-STEP PROCEDURE (19)

Wash Type	Acid Soak	First Rinse	Citric Rinse	Alkaline Boil-out	Calculated Composite
Volume of Water Used (L)	225 000	225 000	225 000	25 000	900 000
Total Alkalinity (mg/L CaCO$_3$)	-	-	-	290	None
Acidity (mg/L CaCO$_3$)	52 000	-	400	-	13 000
Chlorine (mg/L)	45 000	3 5000	-	150	12 000
Sulphate (mg/L)	-	-	-	-	-
Phosphates (mg/L)	-	1	-	64	16
Iron (mg/L)	5 800	370	97	-	1 600
Copper (mg/L)	290	22	9	6	80
Zinc (mg/L)	6	44	-		12
Nickel (mg/L)	450	1	4	1	113

Available data are inadequate for estimating wastewater volumes from pre-operational or operational condenser steamside cleaning.

The wastewater streams from boiler waterside cleaning tend to vary considerably in chemical content over time due to the sequence of chemical solutions and rinses which are used. For example, the wastewater from an initial acid cleaning solution may have a very low pH and be highly contaminated with dissolved metals as well as the excess cleaning chemicals. If this treatment is followed by a basic neutralizing solution then the wastewater stream characteristics rapidly change from low to high pH and from acid to alkaline residues. Table E.13 lists chemicals reported to be used for boiler cleaning at Canadian steam electric stations (12).

The differences in chemical contents of wastewaters from boiler cleaning are indicated in Tables E.12a and E.12b (19) for two different treatments. These data show

TABLE E.12b AVERAGE CHARACTERISTICS OF BOILER CLEANING WASTES FROM A SIX-STEP PROCEDURE (19)

Wash Type	Bromate Soak	Acid Soak	First Rinse	Second Rinse	Alkaline Boil-out	Final Rinse	Calculated Composite
Volume of Water Used (L)	225 000	225 000	225 000	225 000	225 000	225 000	1 125 000
Total Alkalinity (mg/L $CaCO_3$)	-	-	-	-	320		None
Acidity (mg/L $CaCO_3$)	-	63 000	2 000	300	-	-	13 000
Chloride (mg/L)	-	49 000	1 100	130	80	7	10 000
Sulphate (mg/L)	-	75	21	21	14	3	28
Ammonia (mg/L)	6 600	-	-	-	-	-	1 100
Phosphates (mg/L)	-	-	-	-	99	-	20
Iron (mg/L)	-	3 500	200	65	-	-	770
Copper (mg/L)	-	200	14	2	-	-	45
Zinc (mg/L)	-	400	17	3	-	-	84
Nickel (mg/L)	-	300	39	2	-	-	76

TABLE E.13 SOME BOILER WATERSIDE CLEANING CHEMICALS (12)

Acidic and Basic Solvents

- Ammonia
- Ammoniated citric acid
- Ammonium carbonate
- Ammonium hydroxide
- Citric acid
- Dearsol 12
- Hydrochloric acid
- Sodium carbonate

Inhibitors

- Armo HIB 31
- Disodium phosphate
- Dow A-120
- Trisodium phosphate

Passivation/Neutralization

- Ammonia
- Ammonium carbonate
- Cutain II
- Dearborn 63
- Hydrazine
- Soda Ash
- Sodium hydroxide
- Trisodium phosphate

Silica Removal

- Ammonium Bifluoride

Chelating Agents

- cutain II
- Dibasic ammonium citrate
- NTA
- Thiourea

Oxidizing Agents

- Alkaline permanganate
- Nitrite
- Potassium bromate
- Sodium bromate

Wetting Agents

- Detergent
- Surfactant

Other Uses

- Isopropyl Alcohol
- Nutek

high concentrations of several metals in boiler cleaning wastewaters. Iron (Fe) is the most common metal in boiler systems and high Fe concentrations in the wastewaters result from the removal of iron oxide deposits from metal surfaces. Copper-nickel alloys and admiralty metal containing zinc are also common boiler system metals that corrode and concentrate in metal surface deposits.

(e) Boiler Fireside, Air Preheater and Stack Cleaning. In fossil-fuelled stations, the fire, or exterior, side of the boiler and air preheater as well as the interior surfaces of the furnace and stack may accumulate ash, soot, corrosion products and other substances during operation. Stack, furnace, boiler and air preheater locations in a typical power plant are shown in Figure E.10.

To function properly, boiler surfaces must permit the efficient transfer of heat from combustion to the steam cycle water inside the boiler. Similarly, air preheaters transfer heat from exhaust gases to the incoming air for combustion. The

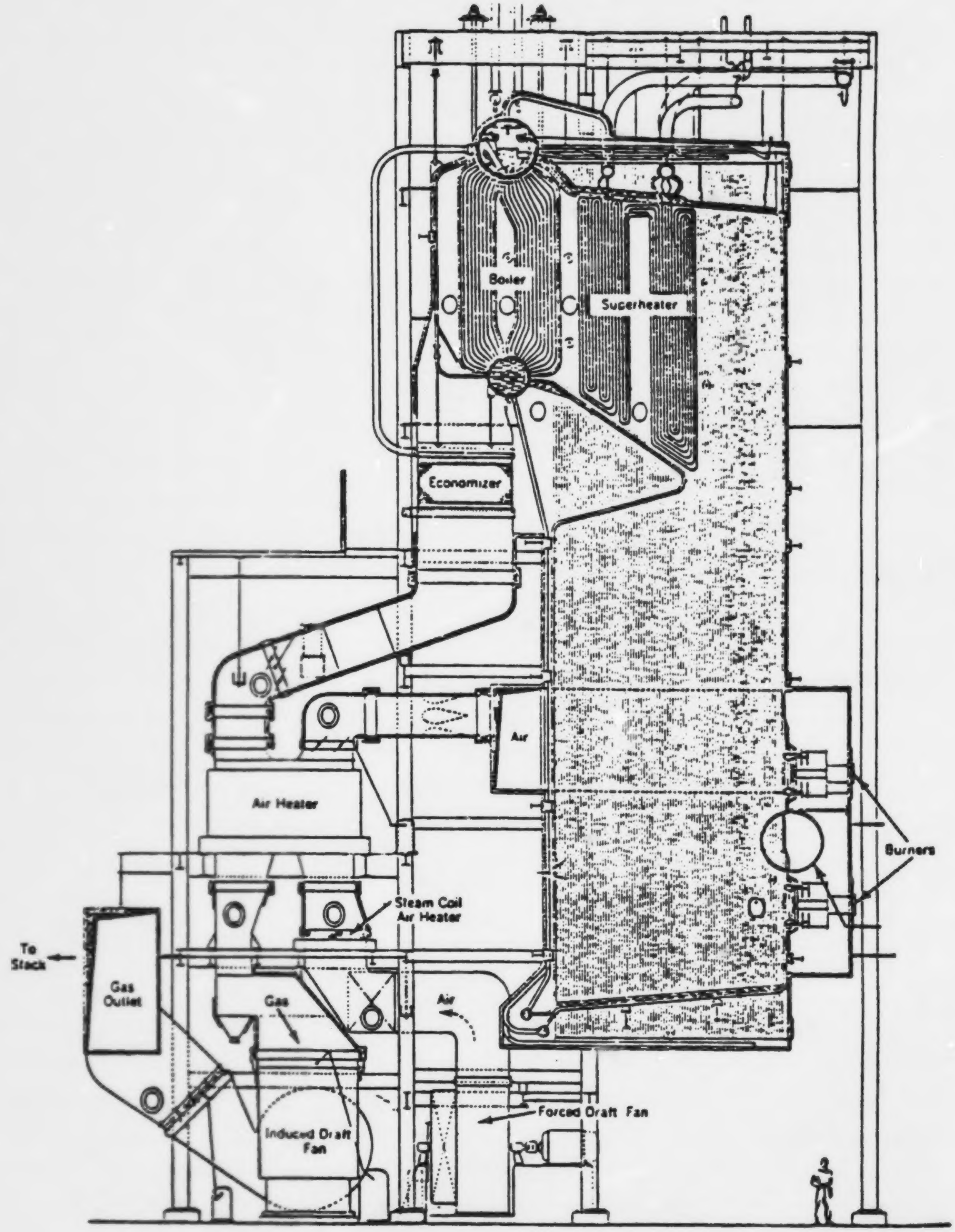

Boiler
Superheater
Economizer
Air
Air Heater
Burners
Steam Coil
Air Heater
To
Stack
Gas
Outlet
Gas
Air
Forced Draft Fan
Induced Draft
Fan

FIGURE E.10 BOILER, STACK AND AIR PREHEATER LOCATIONS IN A TYPICAL FOSSIL FUELLED POWER PLANT (15)

buildup of deposits on these surfaces tends to reduce their heat transfer efficiencies. Deposits may also attack the surface materials chemically and, if the deposits become sufficiently large, may interfere mechanically with system operations.

Cleaning of boiler and air preheater fireside surfaces is normally undertaken with cold and/or hot water sprays or washes which may contain detergents and alkaline additives such as sodium carbonate or sodium hydroxide (12). High pressure water jets are commonly used to mechanically break up and knock off large accumulations of hard deposits from the furnace walls. Other, sometimes novel, mechanical methods (e.g., shotguns for boiler slag) which do not employ a water jet for the breakup of hard deposits may also be used.

Air preheater cleaning tends to be performed more frequently than the fireside cleaning of boiler tubes during maintenance outages. As indicated in Table E.14, air preheater wash frequencies at Canadian stations range from zero to three times per year while boiler fireside cleaning, if it occurs at all, will usually only be performed once a year (12). On the other hand, U.S. data show air preheater cleanings as frequent as 12 times per year and boiler fireside cleanings up to 8 times per year (18). The cleaning frequency depends upon the boiler design and operation and on the type of fuel burned.

Stack cleaning to remove accumulated corrosive substances may only be required once or twice, if at all, during the lifetime of a station. However, acid smut in oil-fired stations may necessitate stack cleaning two to four times per annum (9).

Based on the data presented in Table E.14, Table E.15 shows the range of wastewater volumes that are greater than zero, in $m^3/a \cdot MW$, reported for boiler fireside and air preheater cleaning operations at Canadian stations. Although the number of stations reporting data is small, the ranges compare favourably with similar U.S. data in Table E.16. Using the ranges in Table E.15, annual wash water volumes for a 1000 MW station would be:

- boiler fireside	600 - 13 640 m^3/a
- air preheater	50 - 129 900 m^3/a

The wastewater streams from boiler fireside and air preheater washings where only water is used, tend to be increasingly acidic as the sulphur content of the fuel increases. To neutralize the acid condition and to protect the metal surfaces, alkaline additives may be used in the wash water. Since the air preheater and other fireside surfaces are exposed to fuel combustion residues, the wastewaters generally contain a greater variety of metallic species than waterside cleaning wastewaters (e.g., high

TABLE E.14 WASTEWATER VOLUMES FROM BOILER FIRESIDE AND PREHEATER CLEANING (12)

Station	Boiler Fireside Cleaning		Air Preheater Cleaning	
	Cleaning Frequency (Times/a per boiler)	$m^3/a \cdot MW$	Cleaning Frequency (Times/a)	$m^3/a \cdot MW$
1103 (o)	-	-	as req'd	-
1105 (o)	1	0	1	-
1201 (o)	0	0	3	-
1302 (c)	1	-	1	-
1304 (o)	1	5.82	1	16.4
1306 (c)	as req'd	1.86	1	1.3
1307 (c)	-	-	1	34.8
1310 (o)	-	-	2	18.6
1312 (o)	1	1.70	2	8.5
1313 (c)	-	-	as req'd	0
1407 (c)	never	0	2	-
1408 (c)	as req'd	-	as req'd	-
1411 (o)	not done	0	1	1.2
1413 (o)	not done	0	2	1.7
1414 (o)	none	0	1	129.9
2104 (o)	nil	0	-	-
3104 (c)	soot blow only	0	0.3	5.0
3105 (c)	not done	0	1-2	9.8
3106 (c)	none	0	1	26.0
3109 (c)	-	-	-	-
3110 (c)	1	9.09 - 13.64	2	75.7
3209 (c)	1	0.6	2	14.0
4103 (c)	never	0	0	0
4104 (c)	1	0	1	5.8
4201 (g)	-	-	-	-
4203 (o)	-	-	-	-
4204 (c)	1	-	1	-
4206 (c)	-	-	1	0.05
4305 (g)	-	-	not listed	-
4317 (c)	none	0	0	0
4318 (c)	0	0	0	0
4328 (coke)	none	0	0	0
4330 (c)	none	0	0	0
4331 (g)	-	-	not listed	-
4332 (c)	none	0	0	0
4208			1	26.1

(o) = oil
(c) = coal
(g) = gas

TABLE E.15 SUMMARY OF WASTEWATER VOLUMES FROM BOILER FIRESIDE AND AIR PREHEATER CLEANING AT CANADIAN FOSSIL FUELLED STATIONS (12)

	Wastewater Volume (m^3/a•MW)							
	Boiler Fireside				Air Preheater			
Station type (no. of plants)*	Mean Value	Min. Value	Max. Value	Std. Deviation	Mean Value	Min. Value	Max. Value	Std. Deviation
Coal (2/9)	1.23	0.60	1.68	0.89	13.65	0.05	34.8	12.47
Oil (4**/7)	7.56	1.70	13.64	5.06	36.0	1.2	129.9	48.69
Gas (-)	-	-	-	-	-	- -	-	-
All types (6**/16)	5.45	0.60	13.64	5.12	23.43	0.05	129.9	34.09

* e.g., Coal (2/9) signifies data based on coal fired plants where two plants performed boiler fireside cleaning and nine plants performed air preheater cleaning.

** Two values listed for one station were used as if they were two different plants in order to get a large data set.

TABLE E.16 SUMMARY OF WASTEWATER VOLUMES FROM BOILER FIRESIDE AND AIR PREHEATER CLEANING AT U.S. FOSSIL FUELLED STATIONS (15)

	Wastewater Volume (m^3/a•MW)							
	Boiler Fireside				Air Preheater			
Station type (no. of plants)*	Mean Value	Min. Value	Max. Value	Std. Deviation	Mean Value	Min. Value	Max. Value	Std. Deviation
Coal (42/147)	4.01	0.04	26.25	6.36	20.03	0.01	442.4	43.94
Oil (81/110)	9.67	0.14	96.7	16.3	24.32	0.03	855.0	85.94
Gas (40/56)	4.70	0.008	53.3	9.67	5.25	.003	35.79	8.57

* e.g., Coal (42/147) signifies data based on coal fired plants where 42 plants performed boiler fireside cleaning and 147 plants performed air preheater cleaning.

vanadium levels, due to burning vanadium-containing fuel oil). In addition, air preheater deposits contain more of certain heavy metals such as iron, copper, nickel and chromium (from corrosion of the materials of the preheater elements) than do boiler fireside deposits (20).

Table E.17 shows ranges of suspended solids, copper and iron from a large data base reported for boiler fireside and air preheater wash waterwaters at a variety of U.S. stations. The fuel burned is not indicated in this table.

Air preheater washwater data for a Canadian coal-fuelled station is presented in Table E.18. Table E.19 shows the ranges of several parameters from a number of wastewater samples taken at various times during an air preheater wash at a Canadian oil-fired station. In this case the values for iron range from less than 1 to 1 800 mg/L. The mean value reported for U.S. stations in Table E.17 is 1 953 mg/L.

From the above discussions it is apparent that boiler fireside and air preheater cleaning wastewaters are potential environmental hazards at Canadian stations from the point of view of both the volume generated and the chemical characteristics.

(f) Miscellaneous Plant and Equipment Cleaning and Decontamination. Floors and equipment within a power plant are periodically cleaned with pressurized water, steam, detergents and solvents to remove oil, grease, dust and radioactive contamination.

In fossil-fuelled plants, washing is normally most frequently carried out in the fuel and ash handling areas. For example, coal galleries and the area around coal pulverizers require frequent washing to remove coal dust from floors, walls and equipment.

In nuclear stations, cleaning wastewaters include those generated in the fuelling machine shop and decontamination centre. Decontamination is used to reduce radiation fields in and around a nuclear generating station. A number of decontamination techniques are available. Some of these are chemical processes, and others are physical, such as thermal cycling. Of the chemical processes available, some involve the use of dilute chemical reagent, and others involve the use of concentrated chemical reagents. A process available in Canada for decontaminating CANDU reactors is the proprietary dilute chemical decontamination process called CAN-DECON (1).

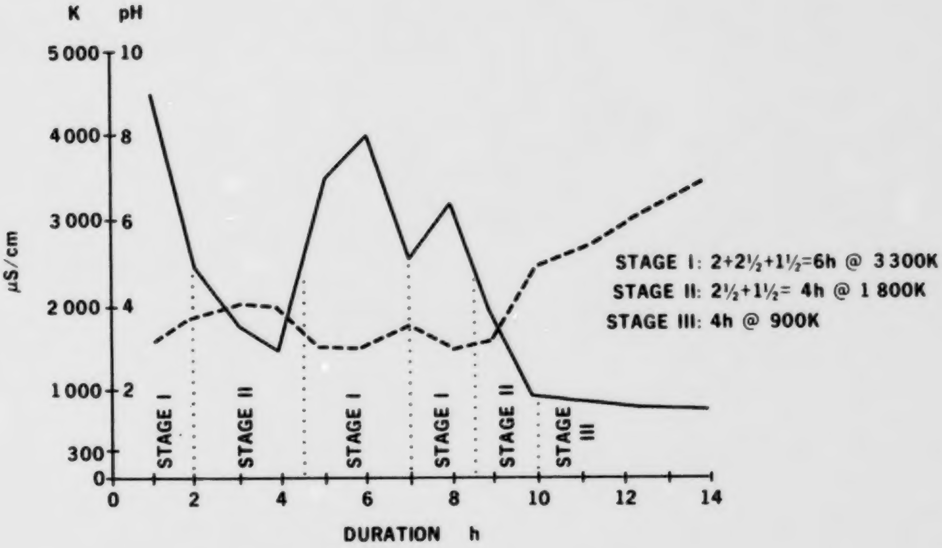
This process involves adding a mixture of weak organic acids and chelating agents directly to the heavy water in the primary heat transport system and circulating it through the entire system. A process of activity removal and reagent regeneration takes

TABLE E.17 SOME CHARACTERISTICS OF BOILER FIRESIDE AND AIR PREHEATER WASHWATERS AT U.S. FOSSIL FUELLED STATIONS (15)

	Boiler Fireside (mg/L)				Air Preheater (mg/L)			
Parameters (number of entries)*	Mean Value	Min. Value	Max. Value	Std. Deviation	Mean Value	Min. Value	Max. Value	Std. Deviation
Suspended Solids (7/78)	15 387	1 194	49 680	19 905	1 268.52	40	10 211	1 663.14
Copper (7/77)	47.82	2.02	127	46.56	148.03	0.1	6 000	815.37
Iron (7/-)	9 680.86	966	40 938	14 699.1	1 953.28	0.05	8 250	2 023.79

* e.g., Suspended solids (7/78) signifies data based on 7 entries for boiler fireside washes and 78 entries for air preheater washes.

TABLE E.18 CHARACTERISTICS OF AIR PREHEATER WASTEWATER AT A CANADIAN COAL FUELLED STATION (21)



Ion	Conc. in Airheater Wash		Conc. in Washing Water		Conc. of Foulants @ 6 300 K	Conc. of Foulants @ 3 300 K	Conc. of Foulants @ 1 800 K	Conc. of Foulants @ 900 K
K	6 300	-	300	=	6 000	3 000	1 500	600
Ca	90	-	40	=	50	25	13	5
Fe	700	-	0	=	700	350	175	70
Na	30	-	15	=	15	8	4	2
Mg	20	-	10	=	10	5	2	1
SO_4	2 300	-	20	=	2 280	1 140	570	228

Quantity of Foulants per Wash		Stage 1	Stage 2	Stage 3	Total
Water	m^3	567.0	378.0	378.0	1 326
Ca	kg	14.2	4.9	1.9	21
Fe	kg	198.5	66.2	26.5	290
Na	kg	4.5	1.5	0.7	7
Mg	kg	2.8	0.8	0.4	4
SO_4	kg	646.0	215.0	108.0	969

TABLE E.19a AIR PREHEATER WASHWATER CHARACTERISTICS FOR CANADIAN OIL-FIRED STATION (22)

Time (minutes) & Side	pH	Dissolved solids (g/L)	Suspended Solids (g/L)	Dissolved Metals mg/L			SO_4 (g/L)	Colour and Remarks
				Fe	NI	V		
0A	2.7	8.9	1.8	330	120	640		hazy blue
5A	3.1	5.7	1.3	110	100	440		yellow-green
7-1/2C	2.9	9.3	1.1	300	120	540		blue
10A	2.7	7.5	0.7	250	140	1 700		hazy green
13B	2.7	10.9	11.6	400	120	750	12.3*	blue-decanted for D.S. and metals
15A	2.7	12.2	1.4	1 600	200	510	7.2	green-blue
15C	2.8	7.3	1.0	360	100	490	4.3	blue
20A	2.8	5.4	6.7	1 500	160	430		blue
20B	3.8	46.4	6.1	1 700	640	1 600		black - shaken for D.S. and metals
20A+B	3.2	27.0	4.5	1 400	350	880	16.5	blue
22-1/2C	2.8	13.8	1.9	1 800	180	500	7.8	blue
25A	3.7	3.7	0.3	690	40	58		nil
25B	2.7	19.4	45.3	1 700	180	910		blue-green decanted for D.S. & metals
30A	3.8	3.7	0.3	590	45	43		light blue
30B	2.9	22.8	4.8	1 600	290	630		black - shaken for D.S. and metals blue
30C	2.8	12.1	0.3	1 500	140	1 100	6.5	light blue
35A	3.8	3.2	0.7	560	40	--		nil
35B	3.4	6.9	14.5	850	62	1 500		blue - decanted for D.S. and metals
37-1/2C	3.1	5.9	1.0	890	64	120		light blue
40A	4.1	1.3	0.3	250	15	3.2		nil
40B	3.4	5.9	16.2	790	50	110	11.8*	blue - decanted for D.S. and metals
45B	4.3	11.5	2.0	940	150	140		black - shaken for D.S. and metals
45C	3.5	3.6	0.3	570	36	54		light blue
50A	4.4	1.4	0.2	200	17	8.4		nil
50B	4.3	11.0	4.0	330	160	280		black - shaken for D.S. and metals
50A and B	4.2	6.4	0.6	290	90	140		light green and hazy
52-1/2C	3.6	3.8	0.2	570	42	59		light blue
55B	3.4	4.3	7.8	310	53	60		pale blue decanted for D.S. and metals
60A	4.6	0.9	0.3	55	10	1.7		nil
60B	3.4	4.0	0.6	320	50	65		nil - decanted
60C	3.8	1.8	0.2	210	20	12		nil
25 201	3.8	3.2	0.4	650	40	36		blue

* sample for sulphate shaken after D.S. determined on decanted sample

TABLE E.19b AIR PREHEATER WASHWATER CHARACTERISTICS FOR CANADIAN OIL-FIRED STATION (22)

Time (hours) & Side	pH	Dissolved solids (g/L)	Suspended Solids (g/L)	Dissolved Metals (mg/L)			SO_4 (g/L)	Colour and Remarks
				Fe	NI	V		
2:00A	3.9	1.0	0.90	130	23	13		nil
2:00B	4.8	11.2	3.6	190	160	170		black - shaken for D.S. and metals
2:00A&B	4.1	6.2	1.2	190	85	97	4.2	green and hazy
2:00C	3.9	1.8	0	120	24	15		nil
2:05A	5.1	0.52	0.06	19	3.5	1.4		nil
2:07-1/2C	4.0	1.2	0.20	90	16	0.5	0.95	nil
2:10A	4.3	0.54	0.14	26	5.3	1.1		nil
2:10B	3.4	5.3	4.8	120	93	67		blue decanted for D.S. and metals
2:15A	6.0	0.57		2.5	---	2.5		nil
2:20B	3.5	3.2	0.7	110	53	57		green decanted for D.S. and metals
2:30A	6.3	0.40	0	90	3.2	2.7		yellow
2:30B	4.2	6.0	1.9	70	100	130		black - shaken for D.S. and metals
2:30A&B	4.4	3.3	0.50	37	54	190		light green
2:37C	5.7	0.61	0.01	3.0	7.0	2.9		nil
3:00A	7.0	0.23	0.04	< 1	1.3	7.1		nil
3:00B	4.2	4.1	1.9	14	1.2	130		yellow decanted for D.S. and metals
3:00A&B	5.0	2.4	0.30	7.5	42	200	1.4	yellow
3:07C	6.1	0.53	0.01	< 1	5.2	11		
3:30A	7.1	0.34	0	1.8	1.6	3.4		yellow
3:30B	6.1	0.24	1.1	< 1	12	59		yellow - shaken for D.S. and metals
3:37C	6.4	0.40	0.07	< 1	3.1	3.6		
3:45A	7.2	0.28	0.28	40	< 1	1.4		nil
4:15B	6.7	0.80	0.30	< 1	8.9	39		nil-shaken for D.S. and metals

place producing a minimum of liquid waste. Spent filters and ion exchange resins are removed and stored in a solid radioactive waste storage facility.

Because activity build-up due to radionuclides other than tritium in CANDU reactors is slow, the CAN-DECON process has seldom been carried out and has only been used in Canada on the primary heat transport circuits (not on moderator circuits) where higher temperatures have resulted in higher levels of activated corrosion products (1).

Decontamination is also carried out by immersing or spraying contaminated equipment with steam or decontamination solutions that will remove corrosion products including radioactive isotopes, from equipment surfaces.

Floors and equipment cleaning wastewaters are collected in floor drains and routed to strategically placed sumps within the plant. Radioactive wastewaters in nuclear stations are routed to the active waste management system by a separate system of collector drains.

The quantities of wastewaters produced by plant and equipment washing and decontamination are not well documented. Preoperational estimates for coal gallery washwaters at one plant indicate that 53 m^3/a·MW is expected from that source (5). Further information on volume estimates for both radioactive and non-radioactive washwaters is presented in Section E.2.5.

The characteristics of plant and equipment cleaning wastewaters vary considerably. They are likely to contain lubricating oils and other oils washed away during equipment cleaning and cleanup after leaks or spills of oils, hydraulic fluids or chemicals; detergents and solvents; dust and other wastes. In coal-fuelled plants, coal or ash fines will be common in washwaters. In nuclear stations, some washwaters are likely to contain a number of radioactive isotopes and reagent chemicals used to remove corrosion products from equipment. Since these wastewaters are combined with other wastes in the active waste management system, their characteristics are discussed further under Section E.2.5.

(g) Laboratory and Sampling Wastes. Steam-electric stations may routinely conduct a variety of analyses on-site to determine the chemical contents or composition of coal, ash, scale and corrosion deposits, boiler water, wastewater streams and other substances whose composition or degree of contaminaton relates to the proper functioning of the station's operating systems. For example, the chemical composition of raw intake water is frequently determined as it may vary with time of year and this may affect the success of the treatments to purify boiler feedwater. Similarly, the nature of scale or corrosion products in boilers influences the selection of specialty chemical additives or cleaning solutions and the amount of remaining contamination in wastewater discharges is a measure of the success of the wastewater treatments. These analyses are generally performed in the station's analytic laboratory.

A wide variety of organic and inorganic chemicals may be kept on inventory in the station laboratory for the required chemical analyses and associated laboratory equipment cleaning. A certain percentage of these will end up in laboratory wastewaters during or after analyses or cleaning operations. Some of the solid and liquid samples that have been analyzed and are no longer required may also be disposed of by releasing or flushing as wastewater.

Wastewaters from laboratories at Canadian generating stations are disposed of in a number of ways (12). At some stations they are discharged directly to receiving waters without treatment. At others, they are either released to the station's sewage treatment plant or a municipal sewer, or treated in some way prior to release. Many laboratories collect and segregate toxic and hazardous wastes (solvents, heavy metals, etc.) for disposal in separate containment facilities (9). Treatment may include neutralization, settling in a holding pond, filtration and discharge to an ash lagoon. In nuclear stations, laboratory wastewaters are directed to the holding tanks of the active waste management system where they are checked for level of radioactivity and, if necessary, treated before release into the condenser cooling water discharge.

Since analytical grade reagents are generally kept on inventory in the laboratory in only small quantities and are securely stored, the quantities that must be disposed of are small. Total amounts of chemicals released to laboratory drains in Canadian steam electric stations are typically in the range of 50 to 200 L/a of liquid and 5 to 20 kg/a of solids, with a maximum annual release reported of 500 L/a (12). Individual releases may be very small amounts (e.g., a few hundred grams, a litre). Similarly, even large composite liquid samples of waste streams tend to be relatively small quantities (a few litres) compared to the station production streams. Wastes from analyses may only be produced in millilitre quantities. Laboratory equipment cleaning wastes are also produced in relatively small quantities (e.g., several litres) periodically.

Chemicals from the laboratory are typically released or flushed with water. Good estimates of total releases are not available, although these are small relative to other wastewaters. In nuclear stations, laboratory wastes will be part of the combined wastewaters released from the active waste management system holding tanks (discussed in Section E.2.5).

Laboratory chemicals, stocked as concentrated, analytical grade liquids and as pure solids, are freshly diluted or dissolved for use. Wastes from analyses tend to be either inorganic liquid composites of the analysed sample residues plus the inorganic reagents, or similar organic mixtures. A list of the more common chemicals released to laboratory drains in Canadian steam electric stations is provided in Table E.20 (12). The chemical contents of the waste streams reflect the different analyses and cleanings performed. In general, these streams are quite toxic. Since acids are among the more common chemicals released, laboratory wastewaters are often of low pH.

In nuclear stations, laboratory wastes are radioactive wastewaters containing tritiated heavy water and/or a variety of fission and activation products. Chemical, tritium, gross beta-gamma, isotopic and other analyses are done in laboratories in the service building. High and low activity drains from these sources may be segregated and routed to the active liquid waste handling system tanks directly through the service building active drainage system. Heavy water samples are not dumped to the chemical laboratory drains. All unused portions of these samples are dumped into carboys or drums and kept for upgrading. Heavy water sample containers are rinsed at the sample stations and the rinsings are also saved for upgrading (1). The isotopic characteristics of laboratory drains will depend on the samples analysed. These drains will contribute to the isotopic characteristics of the combined wastewaters routed to the radioactive liquid holding tanks (see E.2.5).

(h) Sanitary Wastes. In steam electric stations, sanitary wastes include both the food and paper wastes, or garbage, from food preparation and eating areas and the liquid waste streams from cafeterias, restaurants and laundries as well as from showers and washrooms.

Sanitary wastewater streams are generally collected in a common system which is isolated from the wastewater systems for other types of station wastewaters. They may be released directly to the cooling water discharge stream, into a municipal sewer, or routed to an on-site treatment facility. As indicated in Table E.21a (12) separate treatment facilities at existing Canadian generating stations include septic tanks, lagoons, extended aeration and chlorination. In nuclear stations, tritium activity may appear in sanitary wastes from exposed plant personnel. Tritium and mixed fission and other activation products may also originate from personnel showers. These wastes may be discharged to a station or municipal sewage treatment plant. If they are discharged to a municipal sewage treatment plant activity will have to be monitored to

TABLE E.20 CHEMICALS REPORTED RELEASED TO DRAINS IN LABORATORIES AT CANADIAN GENERATING STATIONS (5)

Chemicals Most Commonly Released

- Sulphuric Acid
- Hydrochloric Acid
- Nitric Acid
- Sodium Hydroxide
- Ammonium Molybdate

Other Chemicals Released at One or More Stations

- Citric Acid
- Tartaric Acid
- Perchloric Acid
- Oxalic Acid
- Amino Acid
- Methanol
- N-Hexanol
- Phenol
- Toluene
- Alcohols
- Gylcerin
- Hydrazine
- Methyl Hydrate
- Silver Nitrate
- Potassium Iodide/Iodate
- Potassium Hydroxide
- Ammonium Hydroxide
- Ferric Ammonium Sulphate
- Ferric Nitrate
- Ferric Alum
- Sodium Sulphite
- Barium Sulphate
- Barium Chloride
- Phosphate
- Boron
- Silica
- Carbon Tetrachloride
- Mercuric Chloride
- Benzaldehyde
- Para Amino Benzaldehyde
- Dimethyl Amino Benzaldehyde
- Neslers Reagent
- 1-2-4 Reagent
- Sulphite Reagents
- Caustic
- Other organic solvents and cleaning fluids

TABLE E.21a SEWAGE VOLUMES AND TREATMENT METHODS AT SELECTED CANADIAN GENERATING STATIONS (12)

Station	Domestic Water Consumption (m^3/a•MW)	Sewage Volume (m^3/a•MW)	Sewage Treatment
1105	76	76	Septic tank
1201	1 290	Unknown	None
1304	29	12	None
1306	1 470	5	Extended aeration
1307	570	12	Septic tank
1310	97	5	Municipal
1312	Not available	6	Extended aeration
1313	Not available	6	Extended aeration
1408	440	240	Extended aeration
1413	650	24	Septic tank holding pond
1414	2 570	26	Septic tank, filter, humus tank, Cl
1415	500	7	Settling lagoon, biological treatment
2104	38	4	Oxygenation
3106	240	26	Septic tank, Cl
3107	4 810	Not available	Sewage processing plant
3108	64	51	Municipal
3209	4	2	Lagoon
4103	340	39	Sedimentation, Cl
4104	25	25	Sedimentation, Cl
4206	34	28	Imhoff tank, Cl
4305	7 410	120	Municipal
4318	1 410	1 410	Municipal
4328	10 860	2 020	Lagoons
4330	81	81	3-stage lagoons, cooling pond
4331	1 520	45	Septic tank, underground field

ensure that prescribed limits are not exceeded. Contaminated cotton laundry wastes are routed to the active liquid waste handling tanks in some stations and other nuclear stations employ dry cleaning for the cotton laundry. All laundry wastes from washing of contaminated rubber and plastic clothing are routed to the active liquid waste handling tanks.

Sanitary solid wastes are generally either trucked off-site by a contractor or collected and deposited in sanitary landfills (12).

The volume of sanitary wastewaters produced is related to the domestic water demand. Water demand in turn depends on the number of persons and kinds of facilities (e.g., restaurants, etc.) on-site. Per-person demand will normally be considerably higher for those housed on-site, such as construction workers, than for persons temporarily on-site. Typical per-person demand for those housed on-site is about 300 L/day, while average consumption by a shift worker, temporarily on-site is likely to be about 50 L/day. For comparison, average consumption in restaurants is typically about 25-40 L/day per-person (5,23).

Sanitary wastewater volumes will usually be 60 to 80 percent of domestic water consumption. Wastewater volumes shown in Table E.21a (12) for Canadian generating stations are quite variable on a per MW basis and generally much lower than 60 percent of reported domestic water consumption, although several stations list sanitary wastewater production equal to domestic water consumption. The low percentage return figures may mean that some domestic water volumes reported also include water used for other purposes in the station.

Most stations report sanitary wastewater volumes in the 5 to 100 L/a•MW range. A representative average value might be about 55 L/a•MW (5,24). Hence, sanitary wastewater from a 1000-MW station would typically be between 5 000 and 100 000 m^3/a and average about 55 000 m^3/a.

Sanitary liquid waste streams are occasionally categorized as "grey" or "black" water on the basis of five-day biochemical oxygen demand (BOD_5), and potentially hazardous microorganism contents. Dishwashing and laundry wastewater streams tend to be clasified as "grey" while toilet wastes are "black". Both may contain relatively high concentrations (above 1.0 mg/L) of biologically available phosphorus (from organic wastes and some cleaning compound residues) which may be of concern where eutrophication due to phosphorus tends to be a problem. Other parameters of concern are dissolved solids, suspended solids, BOD, microorganisms (e.g., total and/or fecal coliform) N, pH, and residual chlorine.

Flow and activity data for discharges to the Pickering municipal sewage treatment plant for 1979 are presented in Table E.21b (1).

TABLE E.21b TYPICAL SEWAGE DATA FROM A CANDU NUCLEAR STATION (PICKERING 1979) (1)

Flow Rate (average)		300 000 L/d
Activity		
Tritium[1]	15.6 kBq/L	4.2×10^{-1} μCi/L (max.)[3]
	2.2 kBq/L	6×10^{-2} μCi/L (avg.)
Gross Beta-Gamma[2]	0.19 Bq/L	5×10^{-6} μCi/L (avg.)

1 Calculated on the basis of Bq/annum tritium.
2 Calculated on the basis of Bq/annum gross beta-gamma.
3 These tritium concentrations were higher than "typical" in 1979. The average concentration is more representative.

E.2.3 Wastewaters from Leaks and Spills

(a) Indoor Leaks and Spills (excluding electrical equipment). Leaks and spills of oils, grease, hydraulic fluids and contaminated service waters can be expected to occur within the station during normal power plant operation. These include:

- small leaks of oils, greases and hydraulic fluids that routinely occur from equipment seals and bearings;
- occasional leaks of oils, hydraulic fluids or wastewaters from supply or discharge lines of equipment cooling circuits;
- overflow of ash hoppers and slurry tanks;
- accidental spills of oils, hydraulic fluids and chemicals during transport, machinery fuelling and maintenance operations, or other use in the station;
- occasional large quantity releases of oils or chemicals from breaks or ruptures in large volume fluid or chemical storage vessels, such as acid or caustic storage tanks;
- leaks of heavy water from the moderator and primary heat transport systems in nuclear stations.

Most fluids released during leaks or spills end up in the plant floor drain system. In some cases, small leaks of oils or fluids are absorbed by sorbent materials placed in the drip tray collectors around equipment seals and bearings. Oils collected directly or removed from plant wastewaters by an oil water separator in a sump are often disposed of by dumping them on the coal pile at coal fuelled stations, and by incineration or shipping off-site at other types of stations (12).

Large chemical storage vessels such as acid or caustic tanks for boiler makeup water treatment are commonly located directly above a resistant tile-lined sump of sufficient capacity to contain their contents. Leaks or spills of radioactive substances in nuclear stations will normally be routed either to the heavy water upgrader or to the active liquid waste handling tanks.

Wastewater quantities are highly variable, depending on the source and nature of the leak or spill, and are not well documented. A single event may result in a significant wastewater volume whereas quantities on an average annual basis are not usually very high compared to other plant wastewaters.

The characteristics of leaks and spills are also highly variable. An ash slurry tank overflow or ash slurryline leak will obviously produce an ash laden wastewater. Heavy water leaks in a nuclear station will, if not recovered and upgraded, result in a tritiated heavy water waste stream. Other activation products and fission products may be present. Many of the leaks that occur on a routine basis will consist of oils or hydraulic fluids.

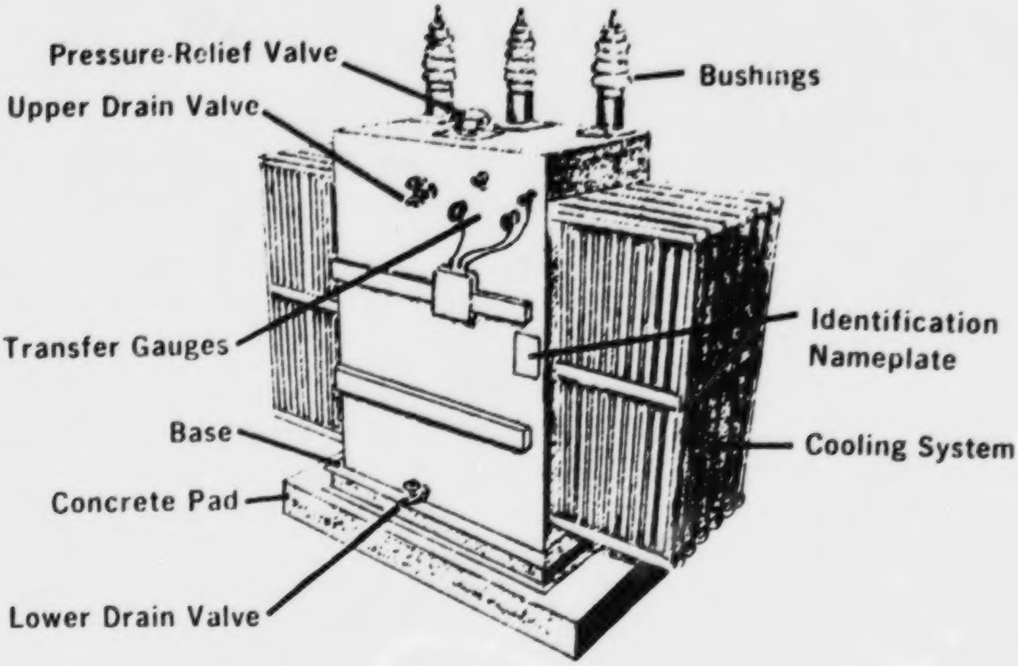
Wastewaters from leaks and spills are often combined with other wastewaters in the plant drain and sump system, or in the active waste management system holding tanks in nuclear stations. Both the quantities and characteristics are further discussed in Section E.2.5 for the resulting combined waste stream, which is the waste stream released from the station.

(b) Electrical Equipment. Electrical equipment in steam electric generating stations can be categorized as:

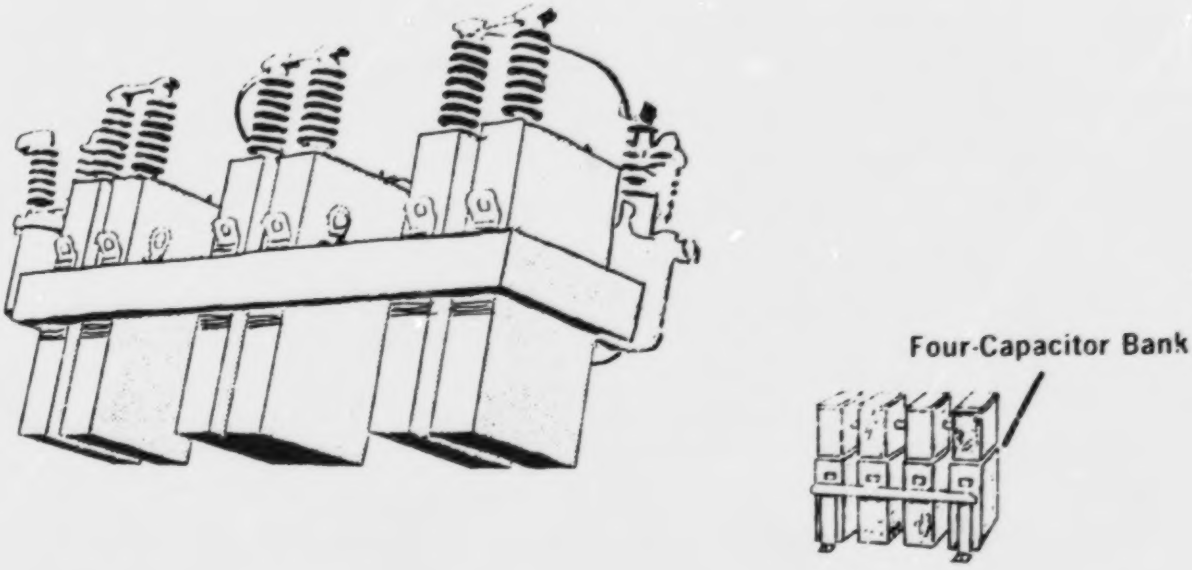
- generator and associated control equipment (switches and circuit breakers);
- transformer and switchyard equipment (circuit breakers, capacitors, rectifiers, etc.);
- electric motor drives.

Illustrations of a transformer and capacitors are provided in Figure E.11 (25,26).

Generators are located in the turbine house as part of turbine generator assemblies. The stator windings of the generator are typically cooled with demineralized water and the rotor is cooled with hydrogen. Heat exchangers are used to dissipate heat produced in the stator windings. Nitrogen and carbon dioxide are commonly used as


Pressure-Relief Valve
Bushings
Upper Drain Valve
Transfer Gauges
Identification Nameplate
Base
Cooling System
Concrete Pad
Lower Drain Valve

(a) Typical Transformer


Four-Capacitor Bank

(b) Typical Capacitor Bank Arrangements

FIGURE E.11 TYPICAL TRANSFORMER AND CAPACITORS (25,26)

purging mediums during commissioning and maintenance. Generator bearings are lubricated with oils or fire resistant hydraulic fluids. Leaks of these fluids from supply lines or around the equipment being serviced represent the only potential for wastewater production from generator operation. Drip trays and other collection devices are usually provided around this equipment as described in Section E.2.8.

Generator control equipment consists of switches and breakers located within the turbine house. These operate at generator voltages (usually 13 kV) and use air as the dielectric (arc control) medium.

Transformers convert electrical energy from one voltage to another for transmission or utilization. A number of small transformers are commonly located within the turbine house to reduce 13 kV generator voltage to the 0.5 to 2.3 kV range for use within the station. The main transformers (typically one per generator) are usually located outdoors along the back wall of the turbine house. These are used to boost the generators' voltages to an appropriate transmission voltage (e.g., 115, 235 or 500 kV). A number of additional transformers are often located in the switchyard to further adjust voltages for specific outgoing transmission lines.

Although some transformers (usually smaller ones) are a dry type, most have their windings and core immersed in a dielectric fluid which is used for cooling as well as insulation (25,27). Heat is transferred through the fluid from the windings to the casing. The entire unit may then be either self-cooled (with exterior fins), water-cooled (with a bank of heat exchange tubes) or forced-air cooled (with fans).

The major potential source of water pollution from transformers is leaks or ruptures of the fluid containment tank and fluid spills during topping up of the tank. A number of Canadian stations report no containment provisions for leaks or spills of transformer fluids (12). Others report the use of dikes, tanks or steel basins for indoor transformers. In a number of cases, the main outdoor transformers have a concrete barrier containment system. Typically, this is part of the transformer foundation and contains a bed of sand, gravel or crushed rock to allow infiltration of fluid leaks and minimization of fire hazard. Transformers in the switchyard are seldom provided with individual containment. However, switchyards are often built on an elevated sand or gravel bed into which fluid leaks or spills will infiltrate.

To prevent transformer oil, or a mixture of transformer oil and water, e.g., from spilling to the receiving waters, containment in the form of pits and holding tanks may be used. The containment may be sized to accommodate the total volume of transformer oil plus 10 minutes of deluge from a fire protection system. The containment may have an oil/water separator so that normal storm water can drain effectively in the absence of oil contamination (28).

Although there are some circuit breakers in the turbine house, the majority are located in the switchyard. The circuit breakers in switchyards operate at higher voltages and may contain oil or use SF_6 (sulphur hexafluoride gas) as a dielectric (arc breaking) medium (SF_6 is also used as an insulating medium in the duct work around busbars). Breaks or leaks in circuit breakers are relatively infrequent and special containment facilities are not normally provided.

All of the capacitors (used for power factor correction) at a steam electric station are located in the switchyard, usually in banks in a separate open bay. The number of capacitors used is highly variable but large stations may have several hundred per generator. Capacitors come in a variety of sizes and are hermetically sealed to reduce the risk of leakage of the fluid they contain (25). However, it is fairly common for capacitors to explode or "blow" thereby releasing the fluid contents. Separate containment around capacitor bays is not often provided, and fluid released when capacitors blow will infiltrate into the gravel base of the switchyard.

The total switchyard area at a steam-electric station can occupy a substantial part of the station site. Examination of areas occupied at several existing generating stations shows a typical range of about 10 to 100 m^2/MW. Based on this, a 1000-MW station would have a switchyard area ranging in size from 1 to 10 ha. Provision of perimeter drains to collect runoff from the switchyard is not common. However, surface drainage by crushed rock chippings is commonly provided. This drainage provides for improved safety of personnel in switchyards since crushed rock has higher electrical resistance than surface water, and drainage allows access for maintenance vehicles (28). A "filter pad" (e.g., peat moss or other absorbent material) may be placed under gravel beds to contain oil spills and protect groundwater (9).

Typically, indoor transformers will not contain more than 3 or 5 m^3 of dielectric fluid with many having much smaller quantities (12). The larger outdoor transformers will contain 10 to 90 m^3 of fluid. In the event of a major leak or rupture of the fluid containment tank of a transformer, these are the ranges of fluid quantities that would be released. Smaller quantities may be released by leakage or weeping through gaskets and seals, and leakage from top or bottom drain spouts, etc. (25,29).

Although the exploding or blowing of capacitors is fairly common, individual capacitors typically will not contain more than a few litres of fluid. For calculation purposes, assuming a 5 percent per year blow rate for capacitors, fluid quantities released annually at a large station would be several dozen litres. Smaller quantities of fluid would normally be released from circuit breakers.

Uncontained releases of fluids from transformers in the station and outdoors along the turbine house wall are likely to find their way into floor or yard drains and eventually be discharged into local receiving waters. Fluid leaks or spills in the switchyard are likely to be gradually washed from the gravel base of the yard by rainfall and appear in runoff from the area. An absorbent filter pad under gravel arrangement would mitigate this (9). A range of possible runoff quantities for a 1000-MW station is provided in Table E.22, assuming switchyard sizes ranging from 1 to 10 ha.

TABLE E.22 PROBABLE RANGE OF RUNOFF VOLUMES FROM THE SWITCHYARD AREA OF A 1000-MW STATION

Percent Precipitation as Runoff	Runoff (m^3/a·1000 MW)			
	Arid Region (Precip 0.4 m/a)		Humid Region (Precip 1.2 m/a)	
	1-ha Area	10-ha Area	1-ha Area	10-ha Area
100	4 000	40 000	12 000	120 000
75	3 000	30 000	9 000	90 000
50	2 000	20 000	6 000	60 000
25	1 000	10 000	3 000	30 000
10	400	4 000	1 200	12 000
5	200	2 000	600	6 000

As indicated in Table E.22, if 50 percent of the precipitation appears as runoff (0.5 runoff coefficient), annual runoff volumes could range from 2 000 to 60 000 m^3 for a 1000-MW station.

The contaminants that may appear in runoff or drain systems depend on the fluids used in transformers and capacitors. In the past, polychlorinated biphenyls (PCBs) have been used (as a principal component of a fluid referred to as "Askarel") in many of the indoor transformers.

Inventory data collected in 1977 (12) on Canadian generating stations showed that at over half the stations with indoor transformers, the transformers were Askarel-filled.

The remainder use mineral oil as a dielectric and cooling fluid, or are air cooled. Only a few Canadian generating stations report the use of Askarel in outdoor transformers; the majority of outdoor transformers are filled with mineral oil.

Since July 1, 1980, the use of PCBs in "electrical capacitors, electrical transformers, and associated electrical equipment manufactured in or imported into Canada" has been prohibited under the Federal Environmental Contaminants Act (PCB Regulation No. 1, Sept. 1, 1977, and amendment, July 1, 1980) (25). PCBs will not be used at any new stations or station expansions and are not considered further in this manual. It can be expected that PCB substitutes other than mineral oil will be used in new transformers having a high fire resistance requirement. Among the more likely alternatives are silicone fluids, chlorinated benzenes, aliphatic hydrocarbons and polyolefins (25,30,31). One or more of these fluids and mineral oil will be the principal contaminants associated with electrical equipment at new stations. If sealed, gas-filled transformers or gas-insulated, vapour cooled transformers become more widely used in new indoor applications, the probability of contaminant releases will diminish (32).

Small quantities of cleaning battery acids or weed control chemicals may also appear in switchyard runoff (12).

(c) Fuel Oil Storage. A sufficient quantity of fuel is stored on-site at most oil fuelled steam electric generating stations to meet fuelling requirements for a specified period of time. The fuel oil is usually stored in an oil tank farm near the station. The quantities stored depend on such factors as plant size and capacity factor, and reliability of supply. Some fuel oil is also stored at most coal fuelled stations for use in boiler ignition and at nuclear stations for emergency and standby power generation. Table E.23(12) provides information on fuel oil stored on-site at a number of Canadian generating stations.

The most significant concerns in terms of contaminated streams from fuel storage are leaks or spills from oil storage tanks or pipes which may be released directly or with runoff from the storage area. Virtually all large fuel oil storage tanks located above ground are surrounded by perimeter dikes, which are commonly sized to contain 110 percent of the capacity of the largest tank within the enclosed area. Wastewaters generated by precipitation and spills are generally routed to an oil separation facility. Recovered oil may be placed in a landfill or pond, burned, placed on the coal pile, recycled to the fuel oil tanks or removed from the site by a contracted disposal company. Information is not available on provisions for containment of oil leaks from tanks located underground. New underground metal tanks are now normally provided with a corrosion protection system such as cathodic protection, to prevent failure and leaks.

TABLE E.23 FUEL OIL TANK FARMS AT SELECTED CANADIAN GENERATING STATIONS* (12)

Station	Tank Farm Area (ha)	No. of Tanks	Total Tank Capacity (m^3)	Containment and Treatment of Wastes
1103		1	8 745	Concrete dike capable of holding contents of tank
1105		4	68 993	Dikes for 4 tanks; wastes collected in slop tank, burned
1201	0.4	1	4 769	1.83 m dike
1304	0.5	3	6 300	Dike to contain capacity of tank; oil wastes separated, landfill or burned
1306	0.15	1	5 630	Dike to contain capacity of tank; oil wastes separated by filter, landfill
1307	0.84	1	14 970	Dike to contain capacity of tank; oil waste separated by filter, landfill
1310	12.1	4	72 973	Dike to contain capacity of tanks; oil waste collected, landfill
1312	0.18	1	8 910	Dike to contain capacity of tank; oil waste collected by oil traps, recovered
1313	1.9	1	20 923	Dike to contain capacity of tank; oil waste collected, landfill
1407	0.81	2	30 549	Gravel dike surrounding both tanks
1411	10	4		dike, gravity separation of waste oil, trucked from site in drums
1413	10	4	129 356	Dike for 110% of tank capacity; underflow baffle separation water to waste treatment facility if >10 mg/l oil
1414	5	4	47 773	Earth dike; drainage to lagoons; oil removed by sludge pump, landfill
2104	10	10	345 268	Dike for 100% capacity of 1 tank in farm of 3 or 4; wastes collected in storage tank, burned or removed by contractor
3104		3	2 500	Dike
3106		5	3 900	Dike, impervious membrane over diked area; wastes spread on coal pile
3109	0.4	5	4 000	Dike for full tank rupture; ring of fire protection nozzles; wastes removed by truck
3110	33	5	26 194 550	Dikes; drainage to oil effluent system; oil separation by gravity, air flotation, surge and floating skimmer, batch ponds; separated oil returned to fuel oil tanks
3209	1	3	3 270	Dikes
4203	1	4	3 000	Earth dike; wastes burned
4206	0.64	1	15 911	2.4 m high dike for 78 m^2 area; waste oil collected in catch pit, removed by contractor
4305	1	4	5 000	Earth berm for large tank, concrete dike for small tanks; wastes collected, recycled and burned
4328	2	2	4 546	Earth dike; wastes to tailings pond

* Only stations with more than 2000 m^3 stored oil and for which information was available are listed

Wastewater quantities arising from precipitation within oil tank farm containment areas will vary considerably. Available data (12) show that oil tank farms range in size from 0.2 to 33 ha for Canadian oil fuelled stations and are usually less than 0.5 ha in area at coal fuelled stations. Using a per-MW range of 1 to 400 m^2/MW, wastewaters from the oil tank farm containment area of a 1000-MW station would range from:

-	arid area (avg. precip. 0.4 m)	400 - 160 000 m^3/a
-	humid area (avg. precip. 1.2 m)	1 200 - 480 000 m^3/a

The principal contaminant in wastewaters from fuel oil storage areas will be oil from leaks or spills within the tank containment area. These may occur during routine operation from minor spills or leaks in valves, pipe connections, etc., or from major incidences such as supply line or storage tank rupture.

d) Roof and Yard Drains. Roof drains are used to collect and convey runoff from the roofs of the power house and other buildings on the generating station site. They are usually sized to accommodate a short duration high intensity rainfall (5). Water collected by roof drains is often discharged into the yard drains on the station site.

Yard drains typically consist of ditches and culverts to collect and convey runoff from the site area. They may also be used to divert natural drainage from upstream of the site around, or re-route it through the site area (5).

The quantities of runoff collected in roof and yard drains will generally be substantially greater than the runoff that occurred naturally from the area prior to development. The impermeable surfaces of buildings and reduced infiltration on the site due to contouring, grading and draining contribute to the increased rate of runoff.

Waters discharged by roof and yard drains are considered wastewaters if there is a potential for contamination by leaks, spills or seepage of oils or chemicals or if there is discharge of contaminated wastewaters into these drains. Some of the potential sources of contamination are not presently controlled at many Canadian generating stations (e.g., switchyard runoff, coal pile runoff, leaks or spills from chemical or fuel handling). These sources may also contain high suspended solids concentrations resulting from runoff from the disturbed and re-contoured surface soils in the site area and from new, unstable channels. Hence, yard drain releases may be potentially contaminated waters (i.e., wastewater) and an order of magnitude estimate of quantities is presented.

The area contributing runoff to yard drains will vary with the size and characteristics of the site. These in turn will depend on factors such as the type and size of station, quantity of on-site fuel storage and methods of waste disposal. From examination of several station site layout drawings and consideration of site component areas (e.g., coal piles, oil tank farms, etc.) discussed in previous sections, it is concluded that areas contributing to site runoff at a 1000-MW station could range from less than 200 000 m^2 to more than a km^2. Using this as a feasible range of areas, site runoff quantities could vary as indicated in Table E.24. If 50 percent of the precipitation appears as runoff, annual runoff volumes from the site of a 1000-MW station would be in the range of 40 000 to 600 000 m^3/a.

TABLE E.24 PROBABLE RANGE OF RUNOFF QUANTITIES COLLECTED BY ROOF AND YARD DRAINS AT A 1000-MW STATION

Percent Precip. as Runoff	Runoff ($m^3/a\cdot 1000$ MW)			
	Arid Region (Precip. 0.4 m/a)		Humid Region (Precip. 1.2 m/a)	
	20-ha Area	100-ha Area	20-ha Area	100-ha Area
100	80 000	400 000	240 000	1 200 000
75	60 000	300 000	180 000	900 000
50	40 000	200 000	120 000	600 000
25	20 000	100 000	60 000	300 000
10	8 000	40 000	24 000	120 000
5	4 000	20 000	12 000	60 000

Since various potential sources of roof and yard drainage water contamination exist, it is difficult to make any reliable prediction of discharge water quality. Assuming that most direct discharges to yard drains will be controlled in some manner, the primary source of contamination is likely to be leaks, spills or seepage of oils and chemicals from such sources as equipment fuelling areas, fuel and chemical storage areas and supply line routes, wastewater discharge pipe routes, etc. Contamination may occur only occasionally and affect only a portion of the site drainage system. If potential sources of contamination are well controlled, site runoff would be similar in quality to natural runoff and would not be considered a wastewater.

E.2.4 Wastewaters from Solid Fuel Storage and Solid Waste Disposal

(a) Coal Transport, Handling and Storage. At coal fuelled stations the size of the coal storage area and quantity of coal stored on site depend on the station size and capacity factor, the proximity of the coal mine, the method and seasonal availability of coal transport and the selected period for reserve. At a typical mine mouth station, a 30-day coal supply may be maintained which, for a 1000-MW station, might require only a few hectares of storage area. However, a station that is remote from the coal source and whose supply is subject to seasonal coal transport restrictions, may need to store a full winter's coal supply on site. For example, the 4 000-MW Nanticoke G.S. in Ontario has an on-site area of 28 hectares to store up to 4 540 000 tonnes of coal for winter use when coal supply over the Great Lakes is not possible. Data on coal storage at Canadian stations are presented in Table E.25 (12, 33) and a typical coal pile configuration is illustrated in Figure E.12 (33).

At coal stations, wastewaters can arise from precipitation on the coal storage, transport and blending areas, and from miscellaneous coal handling equipment cleanings and the use of dust suppression sprays. Figure E.13 (34) is a generalized schematic showing how wastewaters are generated from coal storage piles. Wastewaters are produced by direct runoff from the pile surface and percolation of water through the pile. Also, contaminated water contained in the pile may seep downward through the base of the pile to the groundwater below. As indicated in Table E.25, runoff collection, containment and treatment facilities are provided for coal piles at some Canadian generating stations, while at others there is no containment or treatment. Most coal piles are underlain by native soils of various types and permeabilities, while a few appear to have a compacted clay base.

In general, coal fuelled stations have a larger water requirement and produce larger amounts of wastewater from fuel handling and storage than do oil fuelled stations. Runoff quantities and rates from coal piles will depend on intensity and duration of precipitation, evaporation, rate of percolation into the pile, pile area, area within the containment barrier (if there is one) surrounding the pile and permeability of the soils beneath the containment area. In arid areas, the average percentage return of precipitation on a pile as runoff may be quite low, due to a high evaporation rate and low residual moisture in the pile from fairly infrequent precipitation events. In an area of high precipitation and humidity, both the total runoff and the average percentage return are likely to be higher, with more or less continuous runoff during certain seasons of the year due to larger more frequent rainfalls and the build up and maintenance of a hydraulic head in the pile.

Very few measured flow data are available for runoff from coal piles at Canadian stations (12). A study at one station showed the runoff volume for a series of

TABLE E.25 STORED COAL AT SELECTED CANADIAN GENERATING STATIONS (12, 33)

Station	Coal Pile Area Ha	Coal Pile Height (m)	Coal Pile (m^3)	Volume (m^3/MW)	Water for Dust Suppression (m^3/a)	Coal Pile Base	Runoff Containment/ Treatment
1302	0.50	1.8	9 100	n.a.[a]	Nil	Old railway bed	None, runoff to ditch
1306	0.84	9.1	76 400	362	n.a	Gravel	No containment or treatment
1313	0.9	15	140 000	467	n.a	Gravel over glacial till	Perimeter ditch & collection pond
1408	2.5	10	250 000	2 404	None	No impervious barrier	No special containment, lime added periodically to runoff that collects locally
1413	1.5	4.6	69 000	325	n.a	Low permeability layer	Ditch, pond, reuse, treatment
3104	6.4	4.3	330 000	275	n.a	No impervious barrier	Pile graded to centre, no treatment
3105	12.1	38	3 900 000	1 698	46 000	Packed clay on shale	Ditches, concrete lagoon, lime addition, reuse
3106	7.1	10	705 000	7 050	100	Gravel	No containment or treatment
3109	28	20	5 600 000	1 400	36 000	6 m clay over rock	Ditch, collection sump, ash lagoon
3209	19	9	1 700 000	855	10 000	No impervious barrier	Ditch, pond
4103	6.2	10	620 000	2 616	None	No impervious barrier	No containment or treatment
4104	6.6	10	660 000	5 000	None	No impervious barrier	No containment or treatment
4204	0.65	4.6	30 000	448	n.a.	Clay	No containment or treatment
4206	2.7	11	300 000	1 293	None	0.7m flyash & clay over sand	Natural containment by high ground and railway
4317	0.37	7.6	280 000	77	None	No impervious barrier	Drain to holding pond
4318	1.3	6.0	78 000	134	None	Clay	No containment or treatment
4330	2.0	15	300 000	222	None	Clay	No containment or treatment
4332	18.6	15	2 800 000	18 877[b]	None	No impervious barrier	No containment or treatment

[a] n.a. means "not available".

[b] Quantity is rejects from mining operation and not based on short-term power plant consumption.

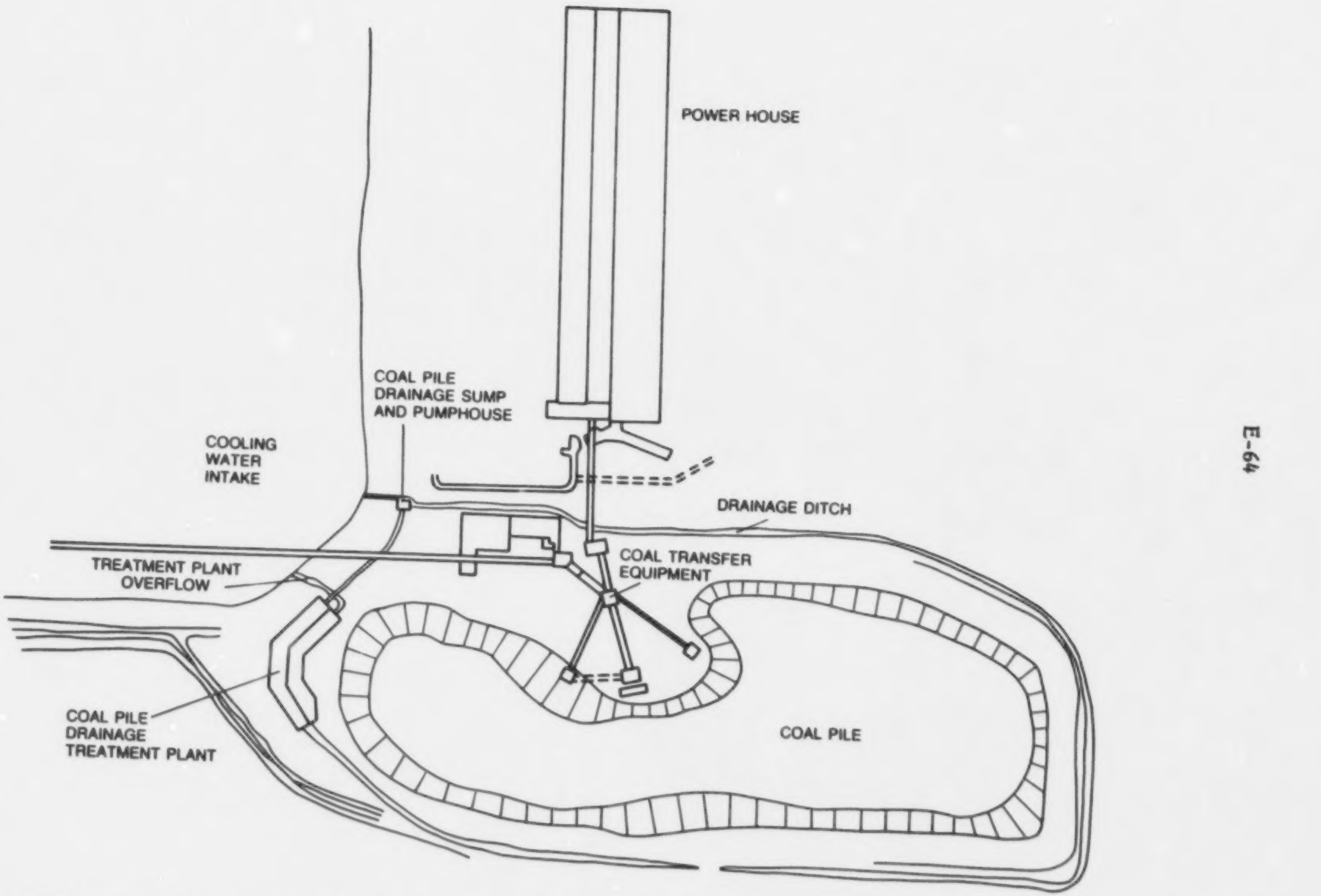

POWER HOUSE
COAL PILE
DRAINAGE SUMP
AND PUMPHOUSE
COOLING
WATER
INTAKE
DRAINAGE DITCH
TREATMENT PLANT
OVERFLOW
COAL TRANSFER
EQUIPMENT
COAL PILE
DRAINAGE
TREATMENT PLANT
COAL PILE

FIGURE E.12 COAL STORAGE AREA AT LAKEVIEW GENERATING STATION (33)

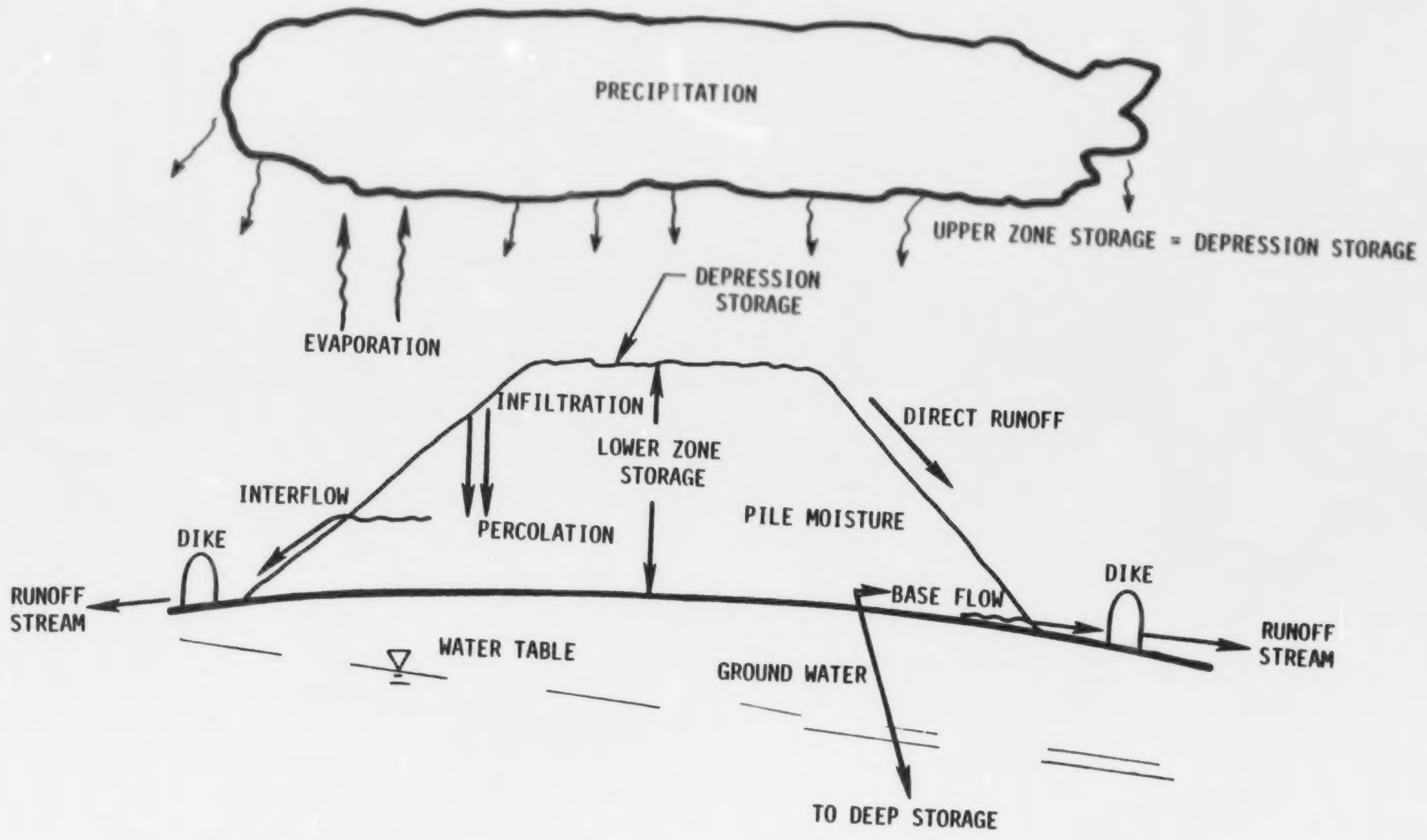

PRECIPITATION
UPPER ZONE STORAGE = DEPRESSION STORAGE
DEPRESSION STORAGE
EVAPORATION
INFILTRATION
DIRECT RUNOFF
LOWER ZONE STORAGE
INTERFLOW
PERCOLATION
PILE MOISTURE
DIKE
DIKE
RUNOFF STREAM
BASE FLOW
RUNOFF STREAM
WATER TABLE
GROUND WATER
TO DEEP STORAGE

FIGURE E.13 GENERALIZED SCHEMATIC OF WASTEWATER GENERATION FROM COAL STORAGE (34)

precipitation events to range from about 5 to 30 percent of the precipitation volumes (35). Another study (36) suggests that on average about 73 percent of the total rainfall can be expected to occur as runoff. A range of potential runoff volumes has been calculated in Table E.26 for different percent releases of rainfall as runoff in arid and humid regions. These calculations assume that 5 and 10 ha would be typical of coal pile containment areas at 1000 MW mine-mouth and remote-from-mine stations respectively.

TABLE E.26 PROBABLE RANGE OF COAL PILE RUNOFF VOLUMES FOR A 1000 MW STATION

Percent Precip. as Runoff	Runoff ($m^3/a \cdot 1000$ MW)			
	Arid Region (Precip. 0.4 m/a)		Humid Region (Precip. 1.2 m/a)	
	Pile Area 5-ha	Pile Area 10-ha	Pile Area 5-ha	Pile Area 10-ha
100	20 000	40 000	60 000	120 000
75	15 000	30 000	45 000	90 000
50	10 000	20 000	30 000	60 000
25	5 000	10 000	15 000	30 000
10	2 000	4 000	6 000	12 000
5	1 000	2 000	3 000	6 000

Based on these studies, it is assumed that annual runoff volume from most coal piles may range from 5 to 75 percent of precipitation. Hence, coal pile runoff quantities from a 1 000 MW station are likely to range from 1 000 to 90 000 m^3/a. If dust suppression sprays are used, the volume could be higher although dust suppression is presumably carried out primarily during dry periods when evaporation is highest.

The concentration of contaminants in coal pile runoff depends on coal type, whether the coal has been washed prior to delivery, extent of exposure to local climatic conditions, characteristics of rainfall events, duration of contact between the water and the coal and extent of compaction of the storage pile (33). Since the coals burned at Canadian generating stations vary considerably in chemical composition, the quality of runoff and seepage from storage piles will also be highly variable. In general, higher sulphur coals will produce a more acidic runoff with higher concentrations of dissolved metals. Concentrations of contaminants will usually be higher from poorly compacted piles with high surface area to volume ratios and enhanced oxidation. It has also been suggested (37) that large, aged coal piles located in areas of frequent rainfall generate much higher effluent concentrations. Concentrations will vary from the beginning to the end of a rainfall event as well as with rainfall intensity and duration.

Table E.27 (33) provides detailed inorganic analyses of coal pile runoff prior to treatment at four Canadian generating stations. The data show pH ranging from a highly acidic 2.1 to an alkaline 8.3. Both total dissolved and total suspended solids are high in most samples and three of the four samples had high sulphate levels (1 400 - 3 600 mg/L). A number of metals occur in concentrations greater than 1 mg/L including Al, Sb, Cr, Cu, Fe, Mn, Ni, Sr and Zn. Concentrations of Al and Fe are quite high ranging from 30 to 60 mg/L and 45 to 500 mg/L, respectively. Figure E.14 shows the variation of metal concentrations over short and extended time spans for two different stations.

Table E.28 (33) presents the results of some preliminary analyses for organic pollutants in coal pile runoff at four Canadian stations. The chemicals included are those on the U.S. Environmental Protection Agency priority substance list (15). While these results indicate only low levels or no contamination of these streams by these particular substances, the possible presence of other classes and kinds of organics was not determined by the particular analytical procedure used in this study (33). Little information is, as yet, available about the presence of other possible substances. Similarly, very little information is available on the presence of organo-metallic species.

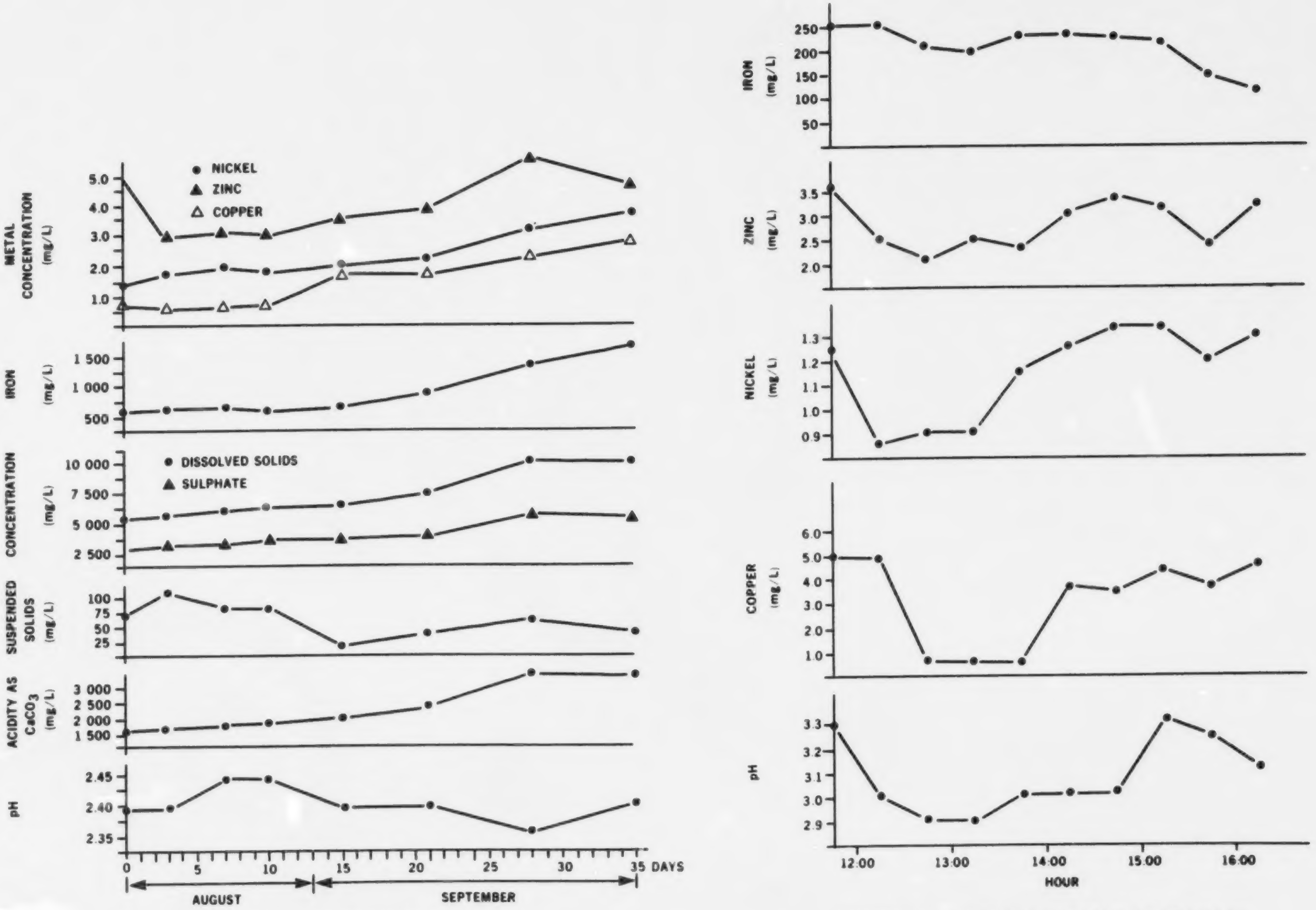
Radionuclides in coal pile runoff and leachates may also be of concern although little comprehensive quantitative data are available. Uranium concentrations in runoff are provided in Table E.27 and some data on leachates generated for several stations in the U.S. under laboratory conditions using de-ionized water are presented in Table E.29 (38). Data for Pb-210, Ra-226 and Po-210 are presented. The highest concentration and activity is for Pb-210, which occurred in an acidic leachate.

(b) Ash Collection, Transport and Disposal. Coal ash now ranks tenth in rate of production among minerals in Canada, with annual production in 1980 of about 3.7 million tonnes (39). Because of the large quantities of ash produced, ash collection transport and disposal are major considerations in site selection and the layout and design of coal fuelled stations.

The quantity of ash produced per megawatt varies considerably with the quality of coal burned. The ash content of coals may vary from 5 to 30 percent or more. A low heating value, high ash content coal will produce much greater quantities of ash than a high heating value, low ash content coal. Table E.30 illustrates this variation.

TABLE E.27 ANALYSES OF COAL PILE DRAINAGE PRIOR TO TREATMENT (33)

Parameter	Concentration (mg/L unless otherwise stated)			
	Station 1313	Station 1310 (Washed Coal)	Station 4317	Station 4332 (mining rejects)
pH	2.1	2.7	6.3	8.3
Total Solids	5 720	5 300	21 000	2 440
Total Dissolved Solids	5 540	4 910	2 300	1 330
Total Suspended Solids	180	390	18 800	2 110
Oil and Grease	1.5	9.3	3.7	11.9
Total Organic Carbon	2.0	97	2 200	310
Chemical Oxygen Demand	43.2	567	8 990	2 470
Hardness ($CaCO_3$)	860	1 920	7 200	2 400
Total Sulphur (SO_4)	3 700	2 700	1 600	150
Sulphate	3 600	2 700	1 400	130
Chloride	580	220	17	2.2
Fluoride	0.4	0.8	4.5	0.3
Inorganic Phosphate (PO_4)	6.1	4.2	22	2.7
Total Phosphate (PO_4)	6.1	4.2	23	3.1
Ammonia (NH_4)	0.6	0.3	1.0	0.1
Aluminum	60	30	360	160
Antimony	1.7	0.2	4.4	0.2
Arsenic	0.65	0.07	0.24	0.04
Barium	0.1	0.1	0.15	0.1
Beryllium	0.01	0.01	0.06	0.01
Boron	0.18	0.43	0.46	0.76
Cadmium	0.12	0.01	0.23	0.01
Calcium	27	170	180	40
Chromium	0.05	0.05	1.30	0.20
Cobalt	0.85	0.28	0.47	0.03
Copper	0.56	0.38	8.2	3.00
Iron	500	370	98	45
Lead	0.1	0.1	0.1	0.1
Lithium	0.25	0.15	0.87	0.17
Magnesium	72	180	140	34
Manganese	21.3	7.50	3.70	4.40
Molybdenum	0.1	0.1	0.1	0.1
Nickel	1.55	0.55	1.65	0.55
Potassium	2.9	6.3	45	26
Selenium	0.02	0.02	0.02	0.02
Silicon	10.3	34.6	1 900	21.0
Silver	0.03	0.02	0.09	0.01
Sodium	450	148	485	31
Strontium	1.3	2.6	5.3	1.3
Thallium	0.2	0.2	0.2	0.2
Thorium	0.06	0.06	0.13	0.06
Titanium	0.3	0.3	18	18
Vanadium	0.1	0.1	0.8	0.1
Zinc	5.4	4.6	4.0	1.4
Zirconium	0.05	0.05	0.37	0.05
Cyanide as CN_4 (µg/L)	20	20	20	20
Thiocyanate as SCN (µg/L)	0.5	0.5	0.5	0.5
Phenol (µg/L)	4.0	1.0	3.5	1.0
Mercury (µg/L)	0.1	1.2	2.7	0.8
Uranium (µg/L)	5	5	66	90



TEMPORAL VARIATIONS IN COAL PILE DRAINAGE LAGOON QUALITY- LINGAN G.S.

TEMPORAL VARIATIONS IN COAL PILE DRAINAGE - LAKEVIEW G.S., SEPTEMBER 2, 1980 ONE RAINFALL EVENT

FIGURE E.14 TEMPORAL VARIATION IN COAL PILE DRAINAGE QUALITY (33)
]

TABLE E.28 ANALYSIS FOR U.S. EPA ORGANIC PRIORITY POLLUTANTS IN COAL PILE DRAINAGE PRIOR TO TREATMENT (33)

Parameter	Station 1313	Station 3105 (Washed Coal)	Station 4317	Station 4322
Purgeable Organics				
Benzene	2.6	1.1	1.6	1.3
Chloroform	9.3	3.7	Trace	Trace
1, 2-Dichloroethane	N.D.	N.D.	Trace	N.D.
Ethylbenzene	N.D.	Trace	N.D.	N.D.
Methylene Chloride	22.0	3.6	2.3	N.D.
1, 1, 2, 2-Tetrachloroethane	N.D.	Trace	N.D.	N.D.
Toluene	1.8	N.D.	Trace	Trace
1, 1, 1-Trichloroethane	1.0	N.D.	Trace	N.D.
Polynuclear aromatics:				
Fluoranthene	N.D.	Trace	7	N.D.
Napthalene	N.D.	N.D.	N.D.	2
Pyrene	N.D.	Trace	N.D.	N.D.
Nitrosamines:				
N - nitrosodiphenylamine	N.D.	N.D.	N.D.	10
Phthalate Esters:				
Butylbenzylphthalate	N.D.	N.D.	N.D.	25
Di-n-butylphthalate	25	2	N.D.	N.D.
Diethylphthalate	N.D.	100	N.D.	N.D.
Bis-(2-ethylhexyl phthalate)	20	Trace	15	Trace
Haloethers:				
Nitrobenzene	N.D.	N.D.	15	N.D.
Others:				
Dodecanol	N.D.	N.D.	2 000	N.D.
Dodecane	N.D.	N.D.	500	N.D.

The following parameters were not detected:

Purgeable Organics:
Acrolein
Acrylonitrile
Bromodichloromethane
Bromoform
Bromomethane
Carbon Tetrachloride
Chlorobenzene
Chloroethane
2-Chloroethylvinyl Ester
Chloromethane
Bis-chloromethyl Ester
Di Bromochloromethane
Di Chlorodifluoromethane
1,1-Dichloroethane
1,1-Dichloroethylene
Trans-1,2-Dichloroethylene
1,2-Dichloropropane
1,2-Dichloropropylene
1,1,2,2-Tetrachloroethene
1,1,2-Trichloroethane
Trichloroethylene
Trichlorofluoromethane
Vinyl Chloride

Acid Group

Base Neutral Group

Polynuclear Aromatics:
Benzo (a) anthracene
Benzo (b) fluoranthene
and/or
Benzo (k) fluoranthene

Pesticide Group

Others:
Indole
Carbazole

Notes: N.D. - Not Detected
Trace - Less than 1 microgram per litre
All analyses expressed as micrograms per litre.

TABLE E.29 RADIONUCLIDE DATA FROM COAL STATIC LEACHATE TESTS (38)

Power Plant	pH	TDS (ppm)	Ra-226 (pCi/l)	% Total	Pb-210 (pCi/L)	% Total	Po-210 (pCi/L)	% Total
M-1	7.8	3000	Blank	-	0.1	0.02	0.2	0.0
M-2	3.8	3600	Blank	-	0.1	0.17	0.2	0.33
M-3	2.9	1700	Blank	-	8.1	10.7	0.3	0.41
M-4	8.3	1300	Blank	-	0.2	0.13	0.3	0.25
M-5	7.9	2300	Blank	-	0.1	0.10	0.3	0.25
M-6	2.7	5900	0.5	0.28	3.2		0.6	1.0

TABLE E.30 ASH PRODUCTION WITH DIFFERENT COAL QUALITIES (1000 MW Station, 80 Percent Capacity Factor, 37 Percent Efficiency)

Coal Characteristics Heating Value (kJ/kg)	Ash Content (%)	Coal Consumption (tonnes/a)	Ash Production (tonnes/a)
28 000	10	2 435 000	243 500
20 000	15	3 409 000	511 350
13 000	30	5 245 000	1 573 500

As Table E.30 indicates, a low grade coal can produce more than six times the ash produced from a high grade coal. With the more widespread use of lower grade coals for power generation in the future, there will be a corresponding increase in the per-MW rate of ash production nationally.

The sale of approximately 27 percent of the ash produced at coal-fuelled stations in Canada for such beneficial uses as cement replacement contributes significantly to the solution of environmental problems with ash disposal.

Ash generated during the combustion of coal or fuel oil can be divided into two types: fly ash and bottom ash. Both forms are initially produced as dry waste. The fly ash is carried from the furnace in the flue gas stream and collected dry by means of a cyclone separator or mechanical precipitator in older stations, and by an electrostatic precipitator or baghouse in newer stations. Small quantities are also collected in air preheater and economizer ash hoppers between the furnace and the precipitators. Fly ash contains the lighter, finer ash particles and usually makes up from 60 to 90 percent of the total ash in a coal-fuelled station that uses front or corner fired boilers. Cyclone boilers, which are not common in Canada, produce a smaller percent of fly ash, i.e., from 20 to 30 percent (9). The bottom ash consists of the heavier, larger particles and slag. It falls into a hopper at the bottom of the furnace during combustion. At a coal-fuelled station, bottom ash is quenched with water in the bottom ash hopper, while at oil fuelled stations the small quantities generated are usually manually removed dry during boiler shutdown. Oil ash may be sold to recover the high vanadium content, i.e., 20-50 percent V_2O_5 (9). A number of alternative systems are available for the transport of ash from the generating station to the disposal area and for ultimate disposal. These include:

(i) Fly ash
  - dry, mechanical (truck, conveyor, etc.) transport to a landfill,
  - recirculating water slurry to a lagoon,
  - once-through water slurry to a lagoon.

(ii) Bottom ash
  - automatic dewatering with drag bar system followed by mechanical transport to a landfill,
  - recirculating water slurry to a hydrobin for dewatering followed by mechanical transport to a landfill,
  - recirculating water slurry to a lagoon,
  - once-through water slurry to a hydrobin for dewatering followed by mechanical transport to a landfill,
  - once-through water slurry to a lagoon.

Either common or separate landfills or lagoons can be used for ultimate disposal with the above systems. In some cases, fly ash and bottom ash may be combined for transport to a common disposal site (e.g., fly ash with dewatered bottom ash on a belt conveyor). When a combined ash lagoon is used for disposal, fly ash and bottom ash may be transported in common or separate slurry pipes to the common lagoon.

Each of the above categories of ash disposal systems is now in use at one or more coal-fuelled generating stations in Canada (12,40,41,42). Once-through water slurry to a lagoon, quite common in older stations, has generally been replaced in more recent designs with dry fly ash/recirculating bottom ash systems, or with recirculating combined ash systems. Most recirculating systems in reality have only partial recirculation with a periodic or continuous blowdown to maintain dissolved solids below scaling concentrations or to get rid of excess water (mainly in areas of high precipitation). Only one Canadian station has an operating complete recirculation combined ash system and one station in

Canada now employs the first automatic dewatering drag bar bottom ash system in North America, which is combined with dry fly ash transport to a landfill (41,42).

When lagoons are used for ash disposal, the disposal area is normally located adjacent to the generating station to minimize the slurry transport (and recirculating water return) distances. Where dry or dewatered ash transport to a landfill is used, the landfill may be located near the station, at a remote location or, in the case of some mine mouth stations, back in the open pit mine. In some cases, ash may be excavated from a lagoon after it has been filled and deposited in a landfill so that the lagoon can be reused. Illustrations of typical ash lagoon and landfill layouts are provided in Figures E.15 (43) and E.16 (44). The configurations and provisions illustrated in Figure E.16 are not recommended in the Design Phase Code (see E.3.4 and E.4.1).

Since most fuel oils contain less than 0.05 percent ash by weight (12), the quantities of ash produced at oil fuelled generating stations are small in comparison to those produced at coal-fuelled stations.

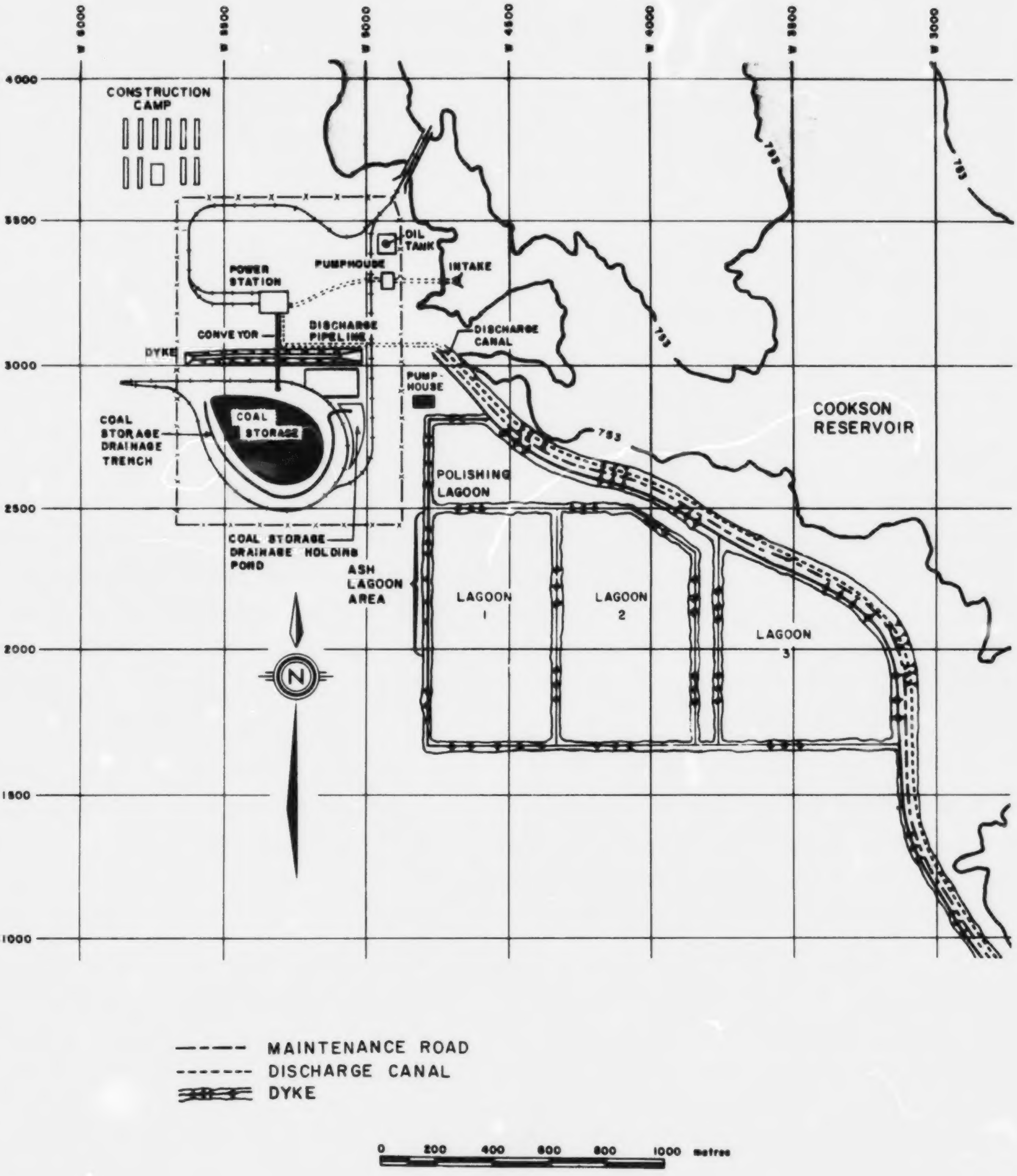
The ratio between bottom ash and fly ash at oil-fuelled stations is similar to that in a coal-fuelled station, with a 25 percent/75 percent split fairly typical. A number of different disposal methods are used for oil ash (12,45). Fly ash disposal methods used include disposal in a landfill or dump, slurry to a lagoon, and reinjection into the boiler. Bottom ash is often put into drums for disposal and in at least one case in Canada is sold for its vanadium content.

Wastewaters from ash disposal can be in the form of:

- direct discharge of ash transport water from a hydrobin or lagoon (once-through water or blowdown),
- runoff from ash disposal landfills,
- seepage from ash lagoons and landfills.

The quantity of wastewater generated by the disposal of ash from coal or oil fuelled stations will depend on the amount of ash produced, the type of ash collection transport and disposal system installed, runoff and seepage contaminant provisions and meteorological conditions in the area. Because of the larger ash volumes, wastewater quantities associated with coal-fuelled station ash disposal will be generally much greater than at oil-fuelled stations.

Once-through slurry systems at coal-fuelled stations require the largest volumes of water per tonne of ash collected and produce the largest quantities of ash contaminated water. Assuming an average six percent by weight slurry and using the


W 6000
W 5500
W 5000
W 4500
W 4000
W 3500
W 3000
N 4000
N 3500
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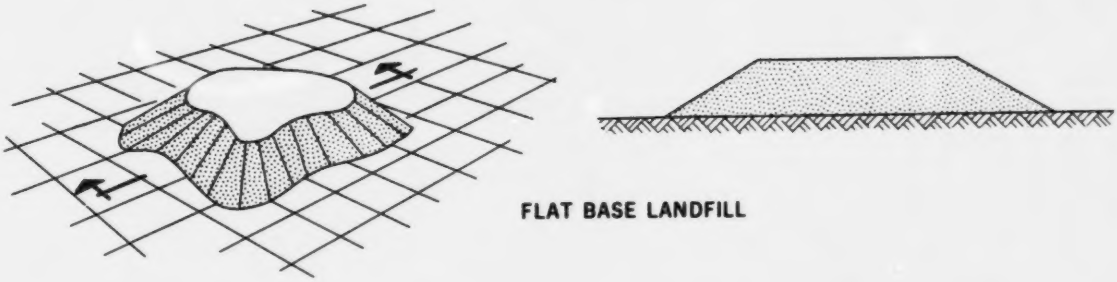
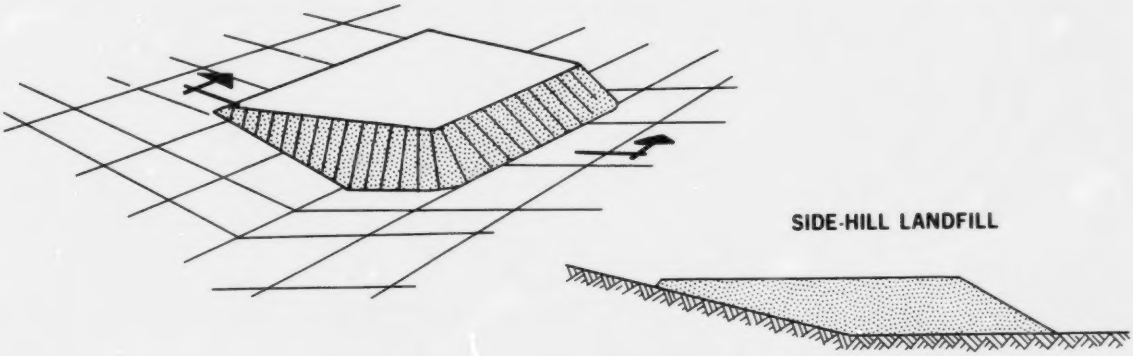
N 2500
N 2000
N 1500
N 1000
CONSTRUCTION CAMP
OIL TANK
PUMPHOUSE
INTAKE
POWER STATION
CONVEYOR
DISCHARGE PIPELINE
DISCHARGE CANAL
DYKE
PUMP-HOUSE
COAL STORAGE
COAL STORAGE DRAINAGE TRENCH
COOKSON RESERVOIR
753
POLISHING LAGOON
COAL STORAGE DRAINAGE HOLDING POND
ASH LAGOON AREA
LAGOON 1
LAGOON 2
LAGOON 3
N
MAINTENANCE ROAD
DISCHARGE CANAL
DYKE
0
200
400
600
800
1000 metres

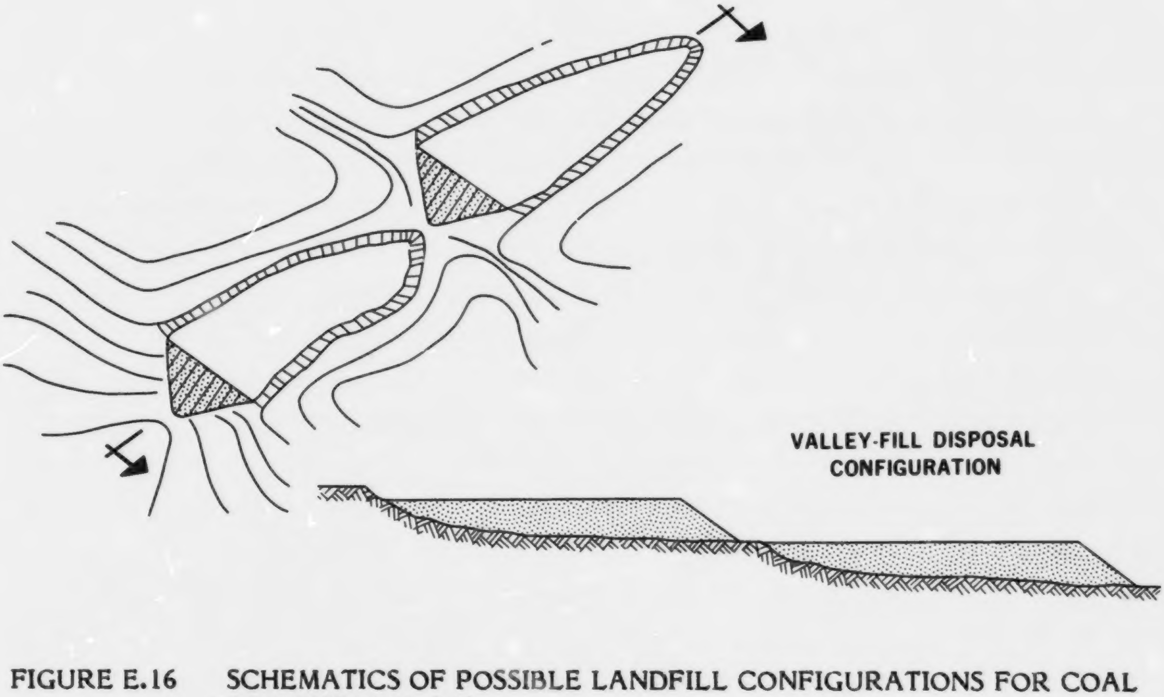
FIGURE E.15 TYPICAL ASH LAGOON LAYOUT AT A COAL-FUELLED GENERATING STATION (43)



FLAT BASE LANDFILL



SIDE-HILL LANDFILL



VALLEY-FILL DISPOSAL CONFIGURATION

FIGURE E.16 SCHEMATICS OF POSSIBLE LANDFILL CONFIGURATIONS FOR COAL ASH DISPOSAL (44)

Note: These configurations are not recommended in Design Phase Code.

annual ash production rates in Table E.30, makeup water to and direct wastewater discharge from a once-through ash lagoon disposal system at a 1 000-MW, 60 percent capacity station could have the range of annual volumes indicated in Table E.31.

TABLE E.31 WATER INTAKE AND WASTEWATER DISCHARGE QUANTITIES FOR A ONCE-THROUGH ASH LAGOON AT A 1000-MW COAL FUELLED STATION

			Wastewater Quantities (m^3/a)		
Ash Production (tonnes/year)	Lagoon Area (m^2)	Water Intake (m^3/a)	0.5 m Excess Evaporation	Evap. Equal Precip.	0.3 m Excess Precip.
243 500	100 000	4.6×10^6	4.01×10^6	4.06×10^6	4.09×10^6
511 350	200 000	8.52×10^6	8.42×10^6	8.52×10^6	8.58×10^6
1 573 500	500 000	26.22×10^6	25.97×10^6	26.22×10^6	26.37×10^6

Ash transport and disposal systems other than once-through systems require smaller water intake volumes and produce smaller quantities of wastewater. Wastewater releases in recirculating lagoon or hydrobin systems are limited to blowdown to maintain solids levels below scaling concentrations and/or to remove excess water from the system in high precipitation areas. In most cases the blowdown rate is not likely to be more than about 10 percent of the slurrywater flow rate. Hence, wastewater quantities would generally be less than 10 percent of those listed in Table E.31 with either a combined ash system or separate fly ash and bottom ash systems operating on a recirculating mode. As some new combined ash systems in arid areas have been designed to operate with no blowdown (42), the feasible range of direct discharge for a recirculating system at a 1000-MW station can be assumed to be 0-10 percent of the quantities listed in Table E.31, or from 0-2.6 x 10^6 m^3/a, depending on site-specific conditions. In ash systems that use dry fly ash transport, direct wastewater discharges are limited to runoff and lateral seepage from the fly ash landfill, combined with releases from the wet bottom ash system. Although high pressure water is used in "hydrovactors" to drawn vacuum to transport ash, this water is not contaminated by ash. Ash is separated from the conveying air before entering the hydrovactors.

Fly ash landfills tend to occupy smaller areas than lagoons because there is no requirement for settling of ash particles and storage of recirculating water. Also there is greater ability to control placement and to develop the deposit to a greater depth. The fill area will be smaller during the early years of station operation and gradually expand to a maximum size at the end of the life of the station. Also, as the area develops, parts of the fill surface area may be reclaimed to such an extent that direct runoff of ash contact water is minimal. Assuming that ash contact runoff at a disposal site for a 1 000 MW station would normally not exceed 20 ha, wastewaters generated from runoff (including lateral seepage) would be as follows:

	Wastewater Quantities (m^3/a)	
	100% precip. as Runoff/Seepage	50% precip. as Runoff/Seepage
- humid area (1.2 m/a precip)	240 000	120 000
- arid area (0.4 m/a precip)	80 000	40 000

A recirculating bottom ash, dry fly ash system could contribute a wastewater quantity up to 40 percent of that from a combined ash recirculating system, i.e., from 0 - 1.0×10^6 m^3/a instead of 0 - 2.6×10^6 m^3/a. A "drag bar" dewatering bottom ash system is expected to use less water and produce less wastewater than a conventional recirculating bottom ash system.

Seepage of ash contact waters into underlying groundwater systems can be a problem with either lagoon or landfill ash disposal. The generally larger areas and greater hydraulic head over extended periods in lagoons make this a more serious problem with lagoons than with landfills. Also, with landfills, controlled placement and compaction of the ash combined with capping and reclaiming of finished sections can substantially reduce infiltration and subsequent seepage to groundwater.

Seepage rates to groundwater are very site-specific and depend on the permeability of the underlying soils. For the lagoon sizes listed in Table E.31, seepage rates could range from only a few L/s to more than 50 L/s for a fairly permeable underlying material. This would give an order of magnitude range for annual seepage volumes of 50 000 to 1 500 000 m^3/a. As can be seen from these numbers, it is possible for downward seepage from a lagoon to substantially exceed the excess rainfall on the lagoon, since water levels in lagoons are maintained primarily by controlled make-up to the system. Downward seepage to groundwater from landfills is likely to be at the lower end of the estimated range of quantities for lagoons and in all cases will be less than the total annual precipitation on the landfill area discussed earlier.

The quality of direct wastewater releases or seepage from ash disposal systems depends on many factors. These include:

- quantities of trace contaminants in the ash;
- leachability of contaminants from the ash;
- major constituents in the ash affecting pH and chemical equilibrium conditions of the leaching medium;
- the ash to water ratio
- cycles of recirculation in lagoon or hydrobin systems (which depends on blowdown and other losses, and determines the number of times fresh ash is added to a given quantity of transport water);
- time of contact of the ash with transport water (which depends on the length of transport lines, rate of settling in a lagoon, etc.);
- time of contact of runoff and seepage waters with the ash in landfills.

Table E.32 summarizes trace element contents of fly ash and bottom ash samples from several Canadian coal fuelled stations (46). Unless they are highly volatile, trace elements will concentrate in the ash during combustion. The degree of volatilization of specific elements at combustion temperatures determines the relative distribution of these elements between the fly ash and bottom ash fractions as well as the quantity emitted from the stack with fine particulates or as vapours. The more volatile elements, such as mercury, selenium and fluorine, will have a strong tendency to vaporize and either condense on the fly ash particles or be emitted as vapour from the stack. Some elements tend to concentrate on the very fine fly ash particles, or cenospheres, due to the high surface area to weight ratios of these particles and longer contact time for vapour condensation. Elements that do not volatilize may melt and become part of either the bottom ash slag or the larger fly ash particles. Some of the vapours from volatile elements may also become trapped and condense inside the larger sized bottom ash particles (15,47,48,49,50).

One classification of the partitioning characteristics of trace elements during coal combustion is as follows (49,51).

Class I elements are not volatilized in the combustion zone, but instead form a rather uniform melt that becomes both fly ash and slag. These elements include Al, Ba, Ca, Ce, Co, Eu, Fe, Hf, K, La, Mg, Mn, Rb, Sc, Si, Sm, Sr, Ta, Th, and Ti.

Class II elements are volatilized on combustion, and condense or adsorb on the fly ash as the flue gas cools, leading to depletion from the slag and concentration in the fly ash. These elements include As, Cd, Cu, Ga, Pb, Sb, Se, and Zn.

TABLE E.32 TRACE ELEMENT CONCENTRATIONS IN ASH FROM CANADIAN COAL FUELLED GENERATING STATIONS (46)

	Station 1306 (Eastern Bituminous)		Station 3105 (U.S. Bituminous)		Station 4207 (Western Lignite)		Station 4317 (Western Subbituminous)	
	Fly Ash	Bottom Ash	Fly Ash	Bottom Ash	Fly Ash	Bottom Ash	Fly Ash	Bottom Ash
Aluminum (mg/kg)*		11.8	7.12	11.7	10.9	11.6	10.1	11.0
Calcium	1.51	1.11	2.39	2.20	13.23	7.20	7.66	5.93
Carbon	1.4	11.2	6.94	3.11	0.12	5.28	0.45	8.00
Iron	14.8	23.9	13.7	19.5	3.79	3.26	4.79	.76
Magnesium	0.71	0.62	0.61	0.58	2.80	1.55	1.05	0.94
Phosphorus	0.13	0.15	0.15	0.11	0.29	0.12	0.22	0.19
Potassium	2.66	1.39	1.64	1.23	0.70	1.03	1.30	1.22
Silicon	20.6	12.6	19.1	18.5	17.2	22.1	22.3	24.3
Sodium	0.49	0.32	0.46	0.38	3.80	3.46	3.25	1.84
Sulphur	0.26	5.98	0.64	0.23	0.39	0.13	0.18	0.09
Titanum	0.43	0.26	0.61	0.56	0.59	0.44	0.26	0.22
Antimony	6.0	6.2	1.3	2.2	6.0	9.0	0.50	0.24
Arsenic	380	97	45	2.6	39	10	54	5.6
Barium	468	124	287	312	8110	7960	3900	3000
Beryllium	2	N.D.	3	3	N.D.	N.D.	N.D.	N.D.
Bismuth	13	9	1.3	0.51	1.1	18	0.25	0.18
Boron	50	10	250	100	600	300	1200	800
Bromine	N.D.	N.D.	3	N.D.	N.D.	N.D.	N.D.	N.D.
Cadmium	0.03	N.D.	N.D.	N.D.	0.03	N.D.	N.D.	N.D.
Cerium	100	64	130	130	130	90	98	100
Cesium	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Chlorine	6.6	18	6.2	9.6	33	11	9.8	5.9
Chromium	145	200	203	200	145	185	103	170
Cobalt	31	41	30	23	10	13	0.24	0.75
Copper	115	125	148	60	88	77	94	53
Europium	3	2	3	N.D.	2	1	1	2
Fluorine	N.D.	N.D.	32	N.D.	16	2	4.1	12
Gadolinium	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Gallium	N.D.	N.D.	40	60	80	30	90	20
Germanium	N.D.	N.D.	40	N.D.	N.D.	N.D.	N.D.	N.D.
Gold	N.D.	N.D.	0.12	N.D.	N.D.	N.D.	N.D.	0.01
Hafnium	5.0	4.6	6.7	14	17	11	10	11
Iodine	1.7	2.4	1.9	0.7	1.6	2.4	2.4	1.3
Lanthanum	65	41	70	2.2	79	55	55	51
Lithium	76	47	132	49	126	97	71	39
Lead	36	14	75	76	30	4	36	35
Manganese	550	830	300	250	150	118	430	480
Mercury	N.D.	N.D.	0.064	N.D.	0.136	N.D.	0.084	0.092
Molybdenum	35	27	67	0.51	15	11	15	3
Nickel	10	55	1.5	100	66	12	19	21
Niobium	N.D.	N.D.	10	10	10	10	N.D.	N.D.
Palladium	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Radium (pCi/g)	2	2	4	3	7	5	5	3
Rubidium	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Samarium	9.2	6.1	12	23	9.5	7.0	8.7	8.0
Scandium	20	12	25	0.5	19	13	13	12
Selenium	3.8	50.0	0.8	0.52	1.0	20	1.5	35
Silver	0.4	0.6	0.4	0.4	0.9	2.4	0.7	0.4
Strontium	510	200	700	760	7600	4100	3600	1900
Tantalum	1.4	0.72	0.90	1.1	2.2	2.1	2.2	2.5
Thallium	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Thorium	16	9	17	17	33	20	22	21
Tin	N.D.	N.D.	N.D.	1	N.D.	N.D.	N.D.	2
Tungsten	1.9	1.3	3.6	3.1	7.4	3.9	9.9	5.7
Uranium	1.2	N.D.	2.1	1.2	3.6	4.5	6.5	2.6
Vanadium	250	422	425	900	199	220	78	20
Ytterbium	4.6	3.1	6.9	14	6.9	5.5	6.0	7.9
Yttrium	20	N.D.	50	50	70	60	50	50
Zinc	466	487	248	140	144	121	197	151
Zirconium	100	65	110	120	220	220	190	200

*Trace constituents are mg/kg unless otherwise noted
N.D. - Not Detected

Class III elements remain almost completely in the gas phase. These elements include Hg, Cl, and Br.

Intermediate between Classes I and II are the elements in coal that cannot definitely be assigned to either class on the basis of the data obtained in the study cited (49,51). Other classifications of partitioning characteristics have also been reported.

The portion of volatile elements retained in the fly ash can increase substantially with a small percentage increase in particulate collection efficiency, when particulate removal is in the 95-99 percent range. A small increase in efficiency will result in a much larger increase in the percent removal of the very fine particle fraction on which trace elements tend to concentrate. Also the type of removal system can effect the collection/emission ratio for trace elements. It has been shown that higher average enrichment occurs in the ash from cold-side than hot-side electrostatic precipitators for the majority of volatilized elements (47). This is probably due to the longer time and lower temperatures for vapour condensation in cold-side systems. The typical trace element removal efficiencies listed in Table E.33 for various emission control technologies provide an indication of the percentage of the available quantities that will be present in the collected flyash (50).

Many trace elements in fly ash and bottom ash are susceptible to dissolution into ash transport waters and precipitation waters, and can occur in varying concentrations in direct ash water discharge or in seepage. The amount of dissolution and wastewater concentrations will depend on the factors listed earlier. The concentrations in once-through ash disposal systems will generally be low in comparison to those in the blowdown from a recirculating system. However, once-through systems can discharge larger total quantities of contaminants than recirculating systems, even if they occur at comparatively low concentrations, because much larger wastewater volumes are discharged. For example, if a metal was dissolved into ash transport water to a 1 mg/L concentration, the quantities released annually at a 1 000 MW station (using the wastewater volumes listed in Table E. 31 for once-through systems) would be:

Wastewater Volume (m^3a)	Quantity of Metal Released at 1 mg/L Concentration (kg/a)
4 060 000	4 060
8 520 000	8 520
26 220 000	26 220

TABLE E.33 TRACE ELEMENT REMOVAL EFFICIENCIES OF VARIOUS CONTROL TECHNOLOGIES (50)

	Average Trace Element Removal Efficiencies (%)					
				SO_2 Scrubber*		
Trace elements	Cyclone separator*	Electrostatic precipitator	Venturi scrubber	Coal-fired boiler	Oil-fired boiler	Baghouse
Aluminium	66.0	99.2	99.6	99.0	92.0	~100
Antimony	7.4	91.2	97.4	99.0	91.0	ND
Arsenic	75.3	95.3	94.2	97.0	81.0	ND
Barium	95.4	98.5	99.3	ND	ND	ND
Beryllium	84.3	98.4	99.2	98.0	ND	ND
Boron	31.4	94.7	93.6*	88.0	93.0	ND
Bromine	ND	99.8*	ND	ND	ND	ND
Cadmium	44.0	95.6	92.3	99.0	77.0	ND
Calcium	54.8	99.1	99.4	99.0	83.0	~100
Cerium	ND	99.1	>99.9*	ND	ND	ND
Cesium	ND	98.9	>99.9*	ND	ND	ND
Chlorine	8.7	4.5*	98.4*	ND	ND	ND
Chromium	27.7	95.1	92.5	95.0	90.0	ND
Cobalt	45.1	98.3	98.4*	99.0	89.0	ND
Copper	56.8	99.2	99.3*	99.0	99.0	~100*
Fluorine	25.3	52.3*	98.0*	ND	ND	ND
Gallium	ND	97.8	99.5*	ND	ND	ND
Iron	54.2	99.1	>99.5*	99.0	95.0	~99.8*
Lead	30.0	95.5	98.0*	99.0	94.0	~100
Lanthanum	ND	99.0	>99.9*	ND	ND	ND
Magnesium	61.0	99.4	99.2	99.0	91.0	ND
Manganese	66.8	99.0	99.4	98.0	87.0	ND
Mercury	3.2	0.0*	12.6*	55.0	87.0	ND
Molybdenum	24.9	92.1	75.6	99.0	89.0	ND
Neodynium	ND	58.7*	99.9*	ND	ND	ND
Nickel	18.6	52.5	95.0*	95.0	83.0	~100
Potassium	ND	99.2	>99.9*	ND	ND	ND
Rubidium	ND	97.0	ND	ND	ND	ND
Scandium	ND	99.0	>99.9*	ND	ND	ND
Selenium	33.1	86.0	91.4	87.0	97.0	ND
Silver	79.6	98.7*	94.8*	ND	ND	ND
Strontium	ND	100.0*	99.8*	99.0	98.0	ND
Thorium	ND	99.0	>99.9*	ND	ND	ND
Titanium	74.4	98.9	99.8	ND	ND	~100
Tungsten	ND	92.8*	97.4*	ND	ND	ND
Uranium	60.6	97.7	97.8	ND	ND	ND
Vanadium	36.2	96.8	98.1	70.0	98.0	ND
Zinc	39.4	97.0	98.4	98.0	90.0	~100
Zirconium	ND	58.6*	>99.9	99.0	94.0	ND
Total ash	65.0	98.8	98.0	ND	ND	ND

ND - No data available.
* Does not represent an average value, since only one data point was available.

The total quantity of all metals released could be substantially higher than the amounts listed, depending on dissolution rates for individual metals.

Table E.34 lists ranges of element concentrations in wastewater releases from once-through ash lagoons at coal-fuelled stations (52-55). A wide range of concentrations can exist because of substantial element variations in different coals, the efficiency of ash collection and the characteristics of the ash and ash transport makeup water. Generally, concentrations will be greater in fly ash contact waters than in bottom ash contact waters. This is due to the greater surface availability of many elements in the fly ash, and because elements tend to be more strongly bonded chemically and physically in a bottom ash matrix. Some investigations have shown that most trace elements in separate bottom ash lagoon discharges are approximately equal to raw makeup water concentrations indicating no significant dissolution from the ash (15). However the discharge of suspended solids would remain a potential concern.

Trace element concentrations in recirculating systems can be expected to build up with the repeated addition of new ash to the transport water. Figure E.17 shows the results of chemical element concentrations in laboratory-simulated recirculating ash system waters for several fly ash and bottom ash types (44). Substantial variations in chemical characteristics occur. Some element concentrations tend to peak at an intermediate number of cycles of ash addition while others continue to rise after as many as 20 cycles. This is due primarily to the relative solubility of the elements, i.e., the least soluble will precipitate out of solution. The boron data plotted in Figure E.18 for the only total recirculation combined ash lagoon currently operating in Canada tend to confirm the experimental data. The plot shows a continuing rise in boron concentrations, although the system has been operating in a recirculating mode for less than a year (42). Some metals will tend to be more soluble in acidic ash water than in alkaline ash water. Acid ash waters are associated with higher sulphur coals. However, even in alkaline ash waters, high levels of contaminants of concern may occur (e.g., B, Mo, Sr, U).

Another study of ash leaching characteristics in recirculating fly ash systems has shown that Se, B, Cr, Ni, Cu, Ba, As, Zn and Al leach most readily from alkaline ash waters, and B, Cd, As, Se, Zn, Ni, Mn, Cu and Ba from neutral ash waters (56). The elements listed are in order of the fraction of total trace metal content released from the ash.

In general, trace element concentrations in the waters of fly ash or combined fly ash/bottom ash recirculating disposal systems will be higher than concentrations in once-through lagoon systems (assuming saturation has not occurred). However, total

TABLE E.34 TYPICAL TRACE ELEMENT CONCENTRATIONS IN WASTEWATER DISCHARGE FROM ONCE-THROUGH ASH LAGOON SYSTEMS AT COAL FUELLED STATIONS (52-55)

Parameter	Mininum*	Maximum*
Alkalinity (as $CaCO_3$)	136.	199.
Aluminum	0.24	19.5
Ammonia (as N)	0.01	6.1
Arsenic	< 0.004	0.015
Barium	0.1	8.63
Boron	0.5	5.1
Cadmium	0.05	7.0
Calcium	16.	51.
Chromium	< 0.001	1.5
Cobalt	0.01	0.02
Copper	< 0.005	0.083
Cyanides	< 0.05	0.061
Fluorides	0.35	0.76
Iron	0.52	3.75
Lead	0.0005	0.13
Magnesium	9.	32.
Manganese	0.003	0.11
Mercury (µg/L)	0.2	14.5
Nickel	< 0.02	0.03
pH	8.3	10.5
Phosphate (total)	0.05	4.0
Selenium	0.0002	0.029
Silica (total)	10.1	20.4
Silver	< 0.0005	0.03
Sodium	35.2	400.
Sulphate	35.	430.
Total Dissolved Solids	25.5	1000.
Total Suspended Solids	0.2	529.
Vanadium	0.0351	0.1101
Zinc	< 0.0001	2.26

* Units - mg/L unless otherwise noted.

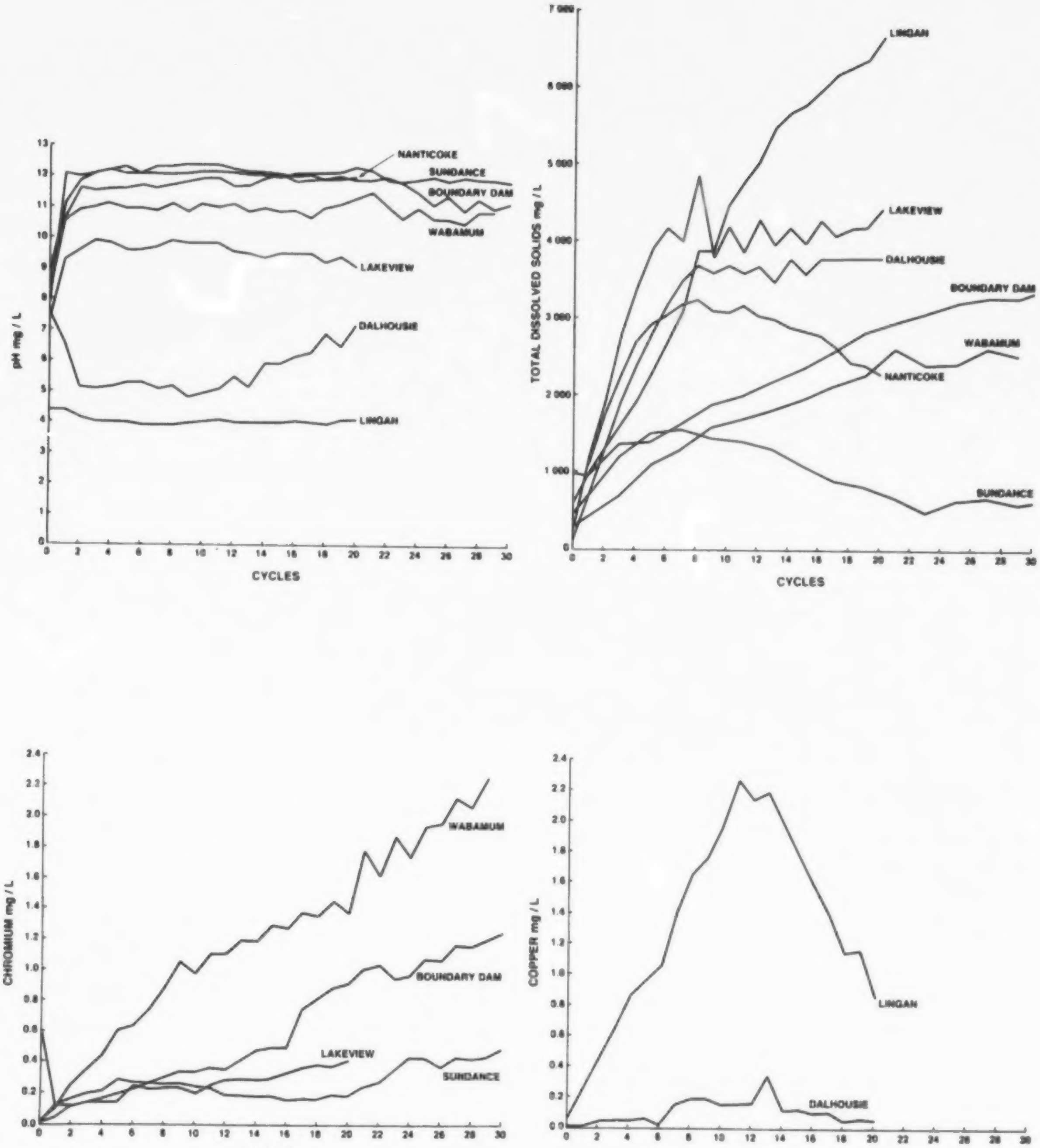


FIGURE E.17 QUALITY OF SIMULATED RECIRCULATING ASH LAGOON WATERS (44)

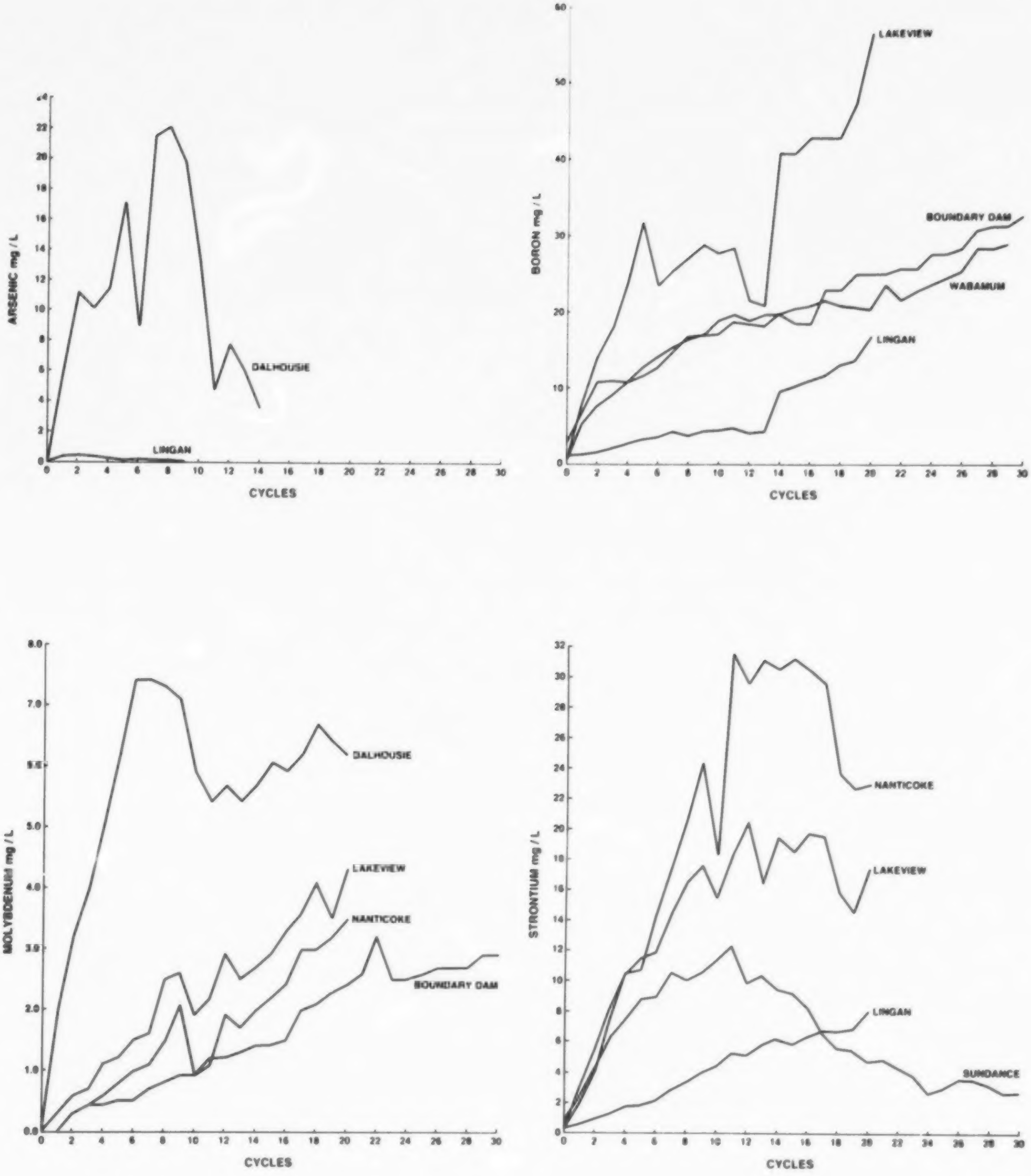


FIGURE E.17 (Cont'd)

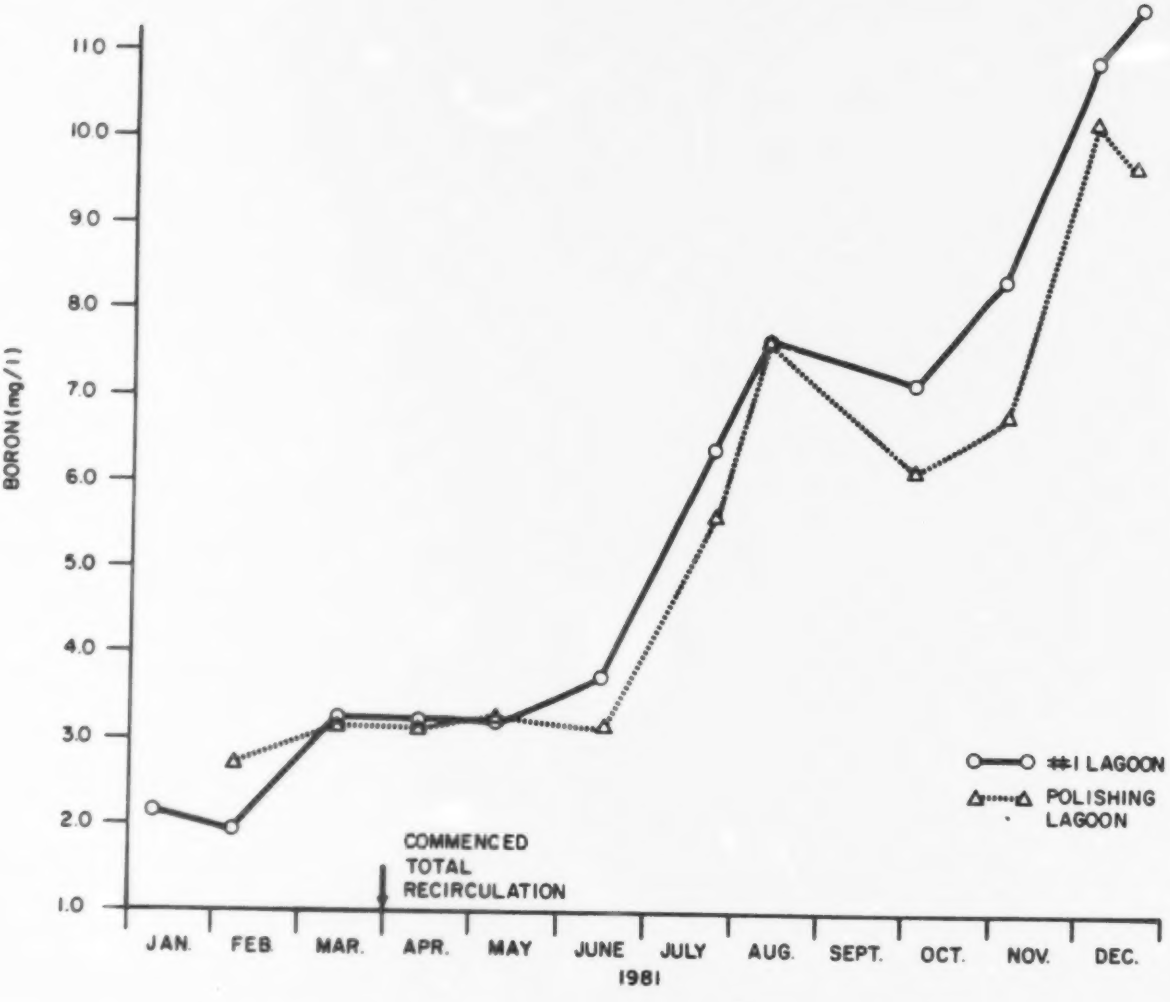


FIGURE E.18 BORON CONCENTRATIONS IN A TOTAL RECIRCULATING ASH LAGOON AT A CANADIAN COAL FUELLED STATION (42)

quantities of trace elements released to the environment via direct discharge will be substantially less from recirculating systems if blowdown rates are low (no release if total recirculation). Blowdown of high concentrations may also be effectively treated to minimize total contaminant release.

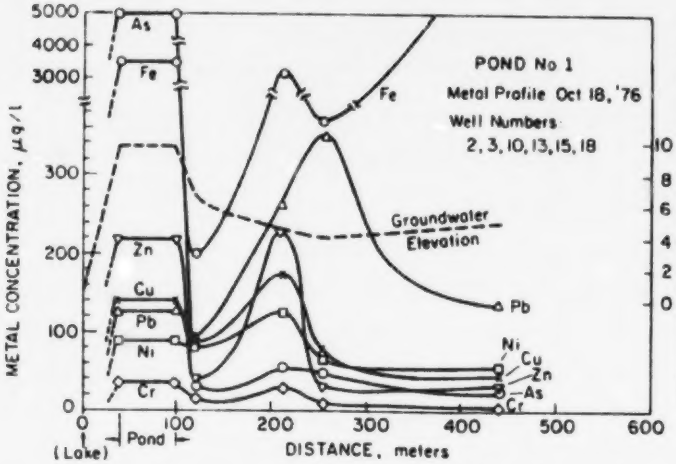
The quality of seepage from ash lagoons or ash disposal landfills will also be highly variable, although very little comprehensive information is available on the quality of seepage waters from ash lagoons at Canadian coal-fuelled stations. Water at the base of an ash lagoon will normally have had a very long contact time with the ash and its quality may not be comparable to the average quality of above-ash water in the lagoon. Also, effective attenuation of many contaminants may occur in the underlying soils depending on the soil and water characteristics (5). One investigation of trace metals in groundwater around a fly ash disposal area showed that rapid attenuation occurred for most metals very close to the ash lagoon, although some peaks did occur in groundwater around the lagoon as shown in Figure E.19. Metals were also found to accumulate in the soil due to precipitation and adsorption. However adsorptive capacity will be exhausted, eventually causing the contaminant front to continually migrate farther from the lagoon (57,58).

The quality of seepage from ash landfills can be expected to be no better, and perhaps worse, than that from lagoons, since the water infiltrating the ash pile will often be exposed to ash that has not been previously leached by transport waters. Table E.35 shows field measurements for interstitial waters (water extracted from ash core samples) and for piezometers at the 14-19 m depth in a fly ash landfill site for a Canadian generating station (59). These data are examples of the quality that might be expected for lateral seepage and seepage to groundwater for a fly ash landfill.

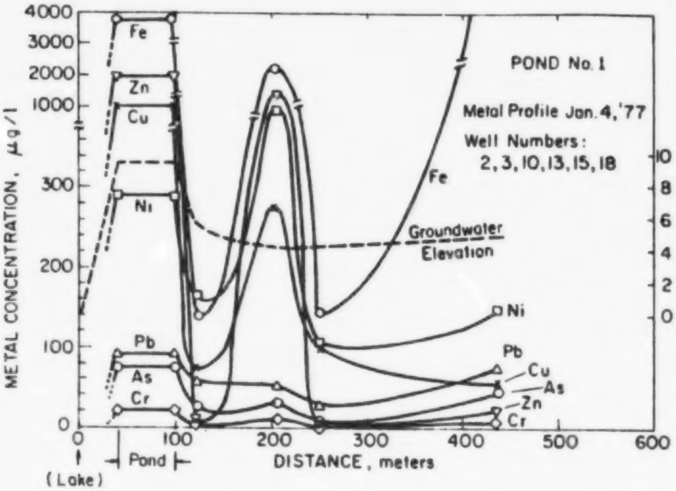
The quality of any direct discharges or seepage flows that may occur from oil ash disposal areas may also be of concern. High concentrations of vanadium (3-14 mg/L) and total dissolved solids (up to 30 000 mg/L) have been shown to occur in oil ash contacted wastewaters (60).

(c) Flue Gas Desulphurization Systems. No flue gas desulphurization (FGD) systems are currently installed at steam electric generating stations in Canada. However, with the recent issuance of federal emission guidelines (61) and the growing concern over acid deposition and air quality deterioration generally, it is probable that such systems will be installed at some fossil-fuelled generating stations in the future.

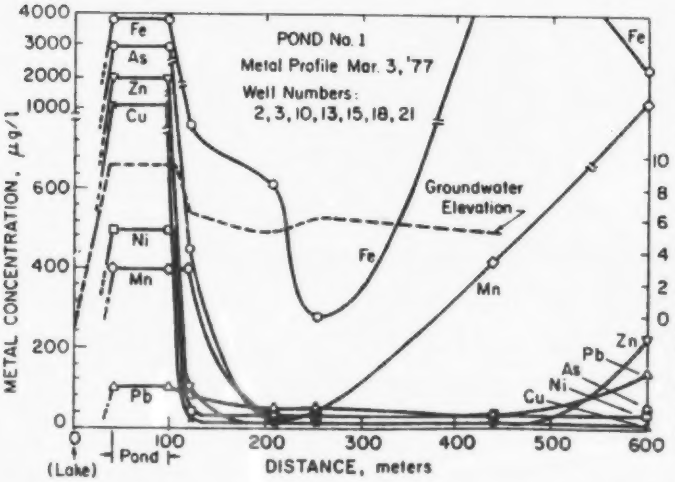
A number of FGD system alternatives are available. The systems in use, undergoing trials or under development in other countries include both nonregenerable



October 18, 1976.



January 4, 1977.



March 3, 1977.

FIGURE E.19 TRACE METAL MIGRATION FROM A FLY ASH LAGOON (59)

TABLE E.35 QUALITY OF SEEPAGE WATERS FROM A FLY ASH LANDFILL (59)

	Mean Interstitial Water	Mean "In Ash" Piezometer
pH	8.6	9.4
Conductivity (Sm/m)	-	355
Alkalinity (OH)*	-	27
(as $CaCO_3$) (CO_3)	-	57
(HCO_3)	-	15
Sulphate	2150	1980
Chloride	100	84
Calcium	460	540
Magnesium	5.4	7.8
Sodium	490	370
Potassium	260	150
Aluminium	2.3	0.6
Boron	51	20
Chromium	-	0.23
Copper	-	0.002
Molybdenum	14	11
Lead	-	0.017
Selenium	-	0.018
Strontium	10	23
Vanadium	0.1	0.07
Zinc	1	0.02

*All units in mg/L unless noted otherwise.

(throwaway) and regenerable media processes. The alternative processes in each of these categories are (11):

Nonregenerable Processes

- lime wet scrubbing
- limestone wet scrubbing
- double alkali wet scrubbing
- spray dryer scrubbing
- lime or limestone alkaline fly ash scrubbing
- sodium carbonate scrubbing

Regenerable Processes

- Wellman-Lord sulphite scrubbing
- magnesium oxide scrubbing
- regenerative aqueous carbonate

All of these processes remove SO_2 from combustion gases by means of a sorbent which absorbs and reacts with the SO_2 and forms sulphur compounds. In the nonregenerable processes, which have been most widely used to date, the sorbent reacts with absorbed SO_2 to produce sulphite and sulphate solids which are then disposed of as a sludge. Particulate removal may be incorporated into the sulphur scrubbing step or the ash may be subsequently mixed with the FGD sludge to improve its compressive strength and impermeability. However, in several FGD systems, ash and scrubber sludge are not mixed.

In regenerable FGD processes, the sorbent is regenerated and reused, while the absorbed SO_2 is either concentrated or converted to hydrogen sulphite. These concentrated, sulphur-containing gases can then be further processed into marketable by-products such as elemental sulphur, sulphuric acid or concentrated SO_2 gas. Particulate removal devices are usually installed up-stream from the FGD system since contamination of the reagent solution with ash is not desirable.

The regenerative systems produce relatively little solid waste since the sulphur compounds are utilized to produce useful end products. However, the non-regenerable systems produce very large quantities of solid wastes and pose a significant waste disposal problem as well as a potential water pollution control problem at the waste disposal site. Table E.36 compares the solid wastes produced by different FGD processes and Table E.37 indicates relative solid waste disposal volume requirements (11). FGD systems may produce sludge volumes ranging from less than five percent of the total ash volume generated to as much as four times the ash volume, depending on the process and the sulphur and ash contents of the original coal. Sulphur dioxide removal requirements will also affect the quantity of FGD sludge produced.

The regenerative systems may produce a small continuous wastewater blowdown. The non-regenerative systems may or may not require this blowdown. Some can be operated as closed water loop systems by dewatering the waste stream and collecting the filtrate and runoff from the disposal area and returning them for re-use in the scrubbing system.

Examples of water, wastewater and solid waste material balances for four common FGD systems are shown in Figures E.20, E.21, E.22 and E.23. These balances were developed for lime, limestone, dual-alkali and Wellman-Lord FGD sytems based on a 500-MW generating station burning 2% sulphur coal. As indicated, all these FGD systems can be designed for zero wastewater discharge, except for the Wellman-Lord process (62). However, some FGD processes may blow down to control chloride and fluoride

TABLE E.36 SUMMARY OF SOLID WASTES PRODUCED BY A 400-MW POWER PLANT BURNING DIFFERENT QUALITY COALS (11)

Coal No.	%S	Coal MJ/kg	% Ash	Absorbant	% Absorbant Utilized	% SO_2 Removal Required by Scrubber	Dry Solids Produced (tonnes x 10^3/a)			
							Fly Ash	Bottom Ash	FGD Sludge	Total
1	0.2	20.9	15	none required	-	-	119	40	-	159
2	0.4	13.9	30	lime	95	35	358	119	9	486
2	0.4	13.9	30	lime-alkaline fly ash	alkaline fly ash	90	-	119	378	497
3	0.8	12.5	13	lime	95	71	172	58	24	254
3	0.8	12.5	13	spray dry-lime -soda ash	59 71	71 71	172 172	58 58	47 50	277 280
4	2.0	27.9	10	lime	95	74	59	20	49	128
4	2.0	27.9	10	limestone	83	74	59	20	54	133
4	2.0	27.9	10	Na_2CO_3[a] -lime -limestone	95[f] 83	74 74	59 59	20 20	49 54	128 133
4	2.0	27.9	10	Na_2SO_3[b]	8[e]	74	59	20	4	83
4	2.0	27.9	10	MgO[c]	3[e]	74	59	20	1	80
4	2.0	27.9	10	Na_2CO_3[d]	5[e]	74	59	20	2	81
5	5.0	30.2	8	Lime	95	89	44	15	136	195
5	5.0	30.2	8	Na_2SO_3[b]	8[e]	89	44	15	10	69

[a] Double alkali process

[b] Wellman-Lord process

[c] Magnesium oxide process

[d] Aqueous carbonate process

[e] Absorbant make-up %

[f] Regenerant lime utilization

Assumptions:
- Based on an average operating load factor of 65%.
- Emission standards: 347 ng/J (0.8 lb SO_2/lb^6 Btu)
  26 ng/J (0.06 lb particulates/10^6 Btu)
- 37% gross energy conservation efficiency.
- Sulphur produced not included as "Dry Solids".

TABLE E.37 SOLIDS DISPOSAL VOLUME REQUIREMENTS FOR A 400-MW POWER PLANT BURNING DIFFERENT QUALITY COALS (11)

Coal No.	%S	Coal MJ/kg	% Ash	FGD Process	Ponding (10^6 m^3) BA	FA	FGD	Total	Landfill (10^6 m^3) BA	FA	FGD	Total
1	0.2	20.9	15	none	0.96	2.88	-	3.84	0.96	2.88	-	3.84
2	0.4	13.9	30	lime	2.89	8.67	0.59	12.15	2.89	8.67	0.37	11.93
2	0.4	13.9	30	lime-alkaline fly ash	2.89	-	9.14^e	12.03	2.89	-	9.14^e	12.03
3	0.8	12.5	13	lime	1.38	4.16	2.59	8.13	1.38	4.16	1.70	7.24
3	0.8	12.5	13	spray dry -lime -soda ash	1.38	4.16	0.67^e 0.70^e	6.21 6.24	1.38	4.16	0.67^e 0.70^e	6.21 6.24
4	2.0	27.9	10	lime	0.47	1.44	3.03	4.94	0.47	1.44	1.99	3.90
4	2.0	27.9	10	limestone	0.47	1.44	3.37	5.28	0.47	1.44	2.19	4.10
4	2.0	27.9	10	Na_2CO_3^{a} -lime -limestone	0.47	1.44	3.03 3.37	4.95 5.28	0.47	1.44	1.99 2.19	3.90 4.10
4	2.0	27.9	10	Na_2SO_3^{b}	0.47	1.44	0.26	2.17	0.47	1.44	0.18	2.09
4	2.0	27.9	10	MgO^c	0.47	1.44	0.04	1.95	0.47	1.44	0.03	1.94
4	2.0	27.9	10	Na_2CO_3^{d}	0.47	1.44	0.11	2.02	0.47	1.44	0.07	1.98
5	5.0	30.2	8	lime	0.35	1.05	8.44	9.84	0.35	1.05	5.49	6.89
5	5.0	30.2	8	Na_2SO_3^{b}	0.35	1.05	0.67	2.07	0.35	1.05	0.42	1.82

[a] Double alkali process

[b] Wellman-Lord process

[c] Magnesium oxide process

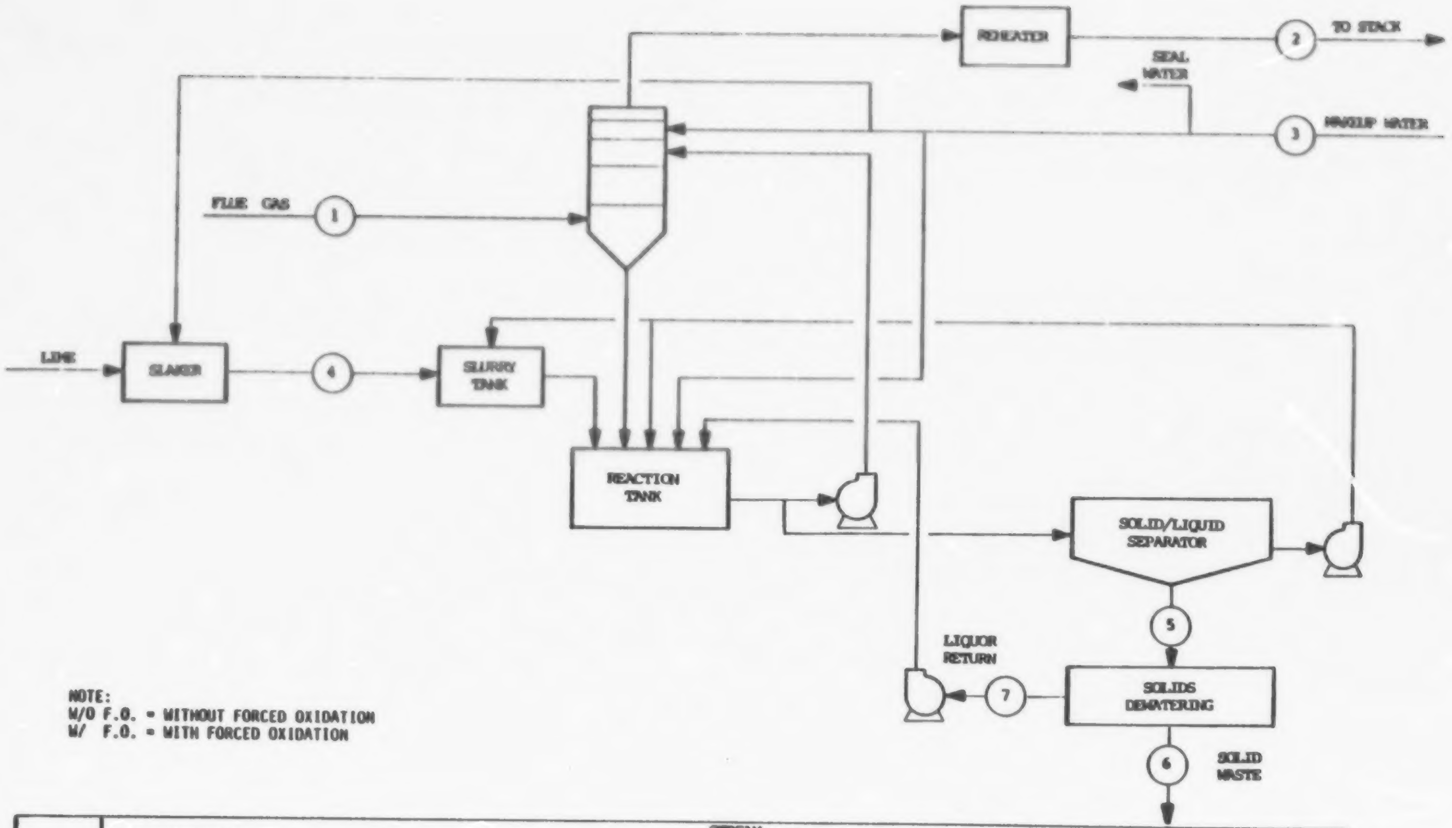
[d] Aqueous carbonate process

[e] Dry bulk density 1.44 g/cm^3

BA = bottom ash
FA = fly ash

Assumptions:
1) 35 year plant life; 65 percent load factor.
2) Dry bulk density: ponding FGD 0.56 g/cm^3
landfill FGD 0.86 g/cm^3
BA = FA = 1.44 g/cm^3

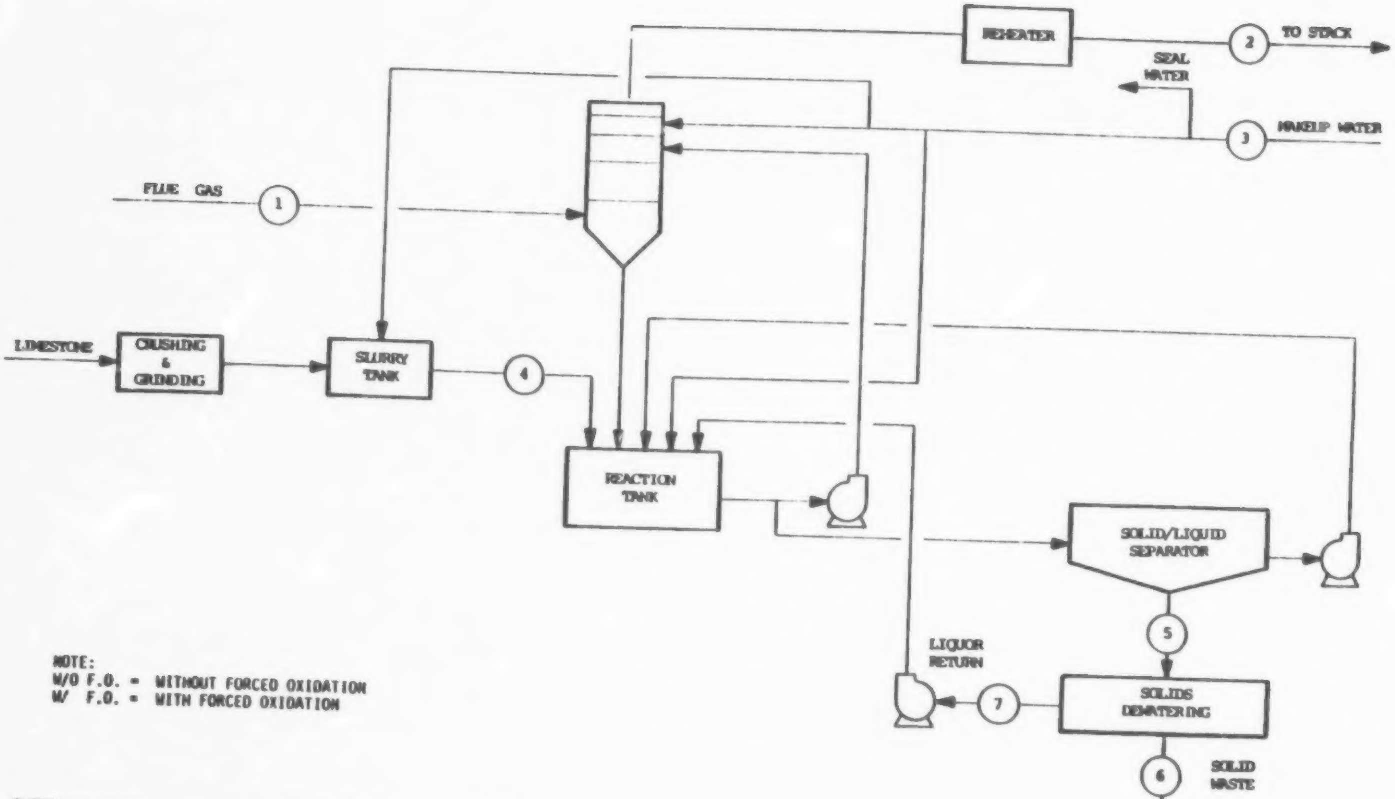
Factors:
Volume (m^3) x 10^{-4} = hectare metres
hectare x 2.4710 = acres


REHEATER
2
TO STACK
SEAL WATER
3
MAKEUP WATER
FLUE GAS
1
LIME
SLAKER
4
SLURRY TANK
REACTION TANK
SOLID/LIQUID SEPARATOR
5
LIQUOR RETURN
7
SOLIDS DEWATERING
6
SOLID WASTE

NOTE:
W/O F.O. = WITHOUT FORCED OXIDATION
W/ F.O. = WITH FORCED OXIDATION

FGD Mode	STREAM 1			2		3	4		5		6		7
	Gasflow (Nm^3/min)	Sulphur (kg/min)	Water (kg/min)	Sulphur (kg/min)	Water (kg/min)	Water (kg/min)	Lime (95% CaO) (kg/min)	Water (Inc. H_2O of Hydration) (kg/min)	Solids (kg/min as $CaCO_3$ & hydrated $CaSO_x$)	Water (kg/min including H_2O of Hydration)	Solids (kg/min as hydrated $CaSO_x$)	Water (kg/min including H_2O of hydration)	Water (kg/min)
W/O F.O.	25,250	52	1,739	10	3,282	1,684	80	220	187	454	187	141	313
W/ F.O.	25,250	52	1,739	10	3,282	1,640	80	220	222	561	222	97	464

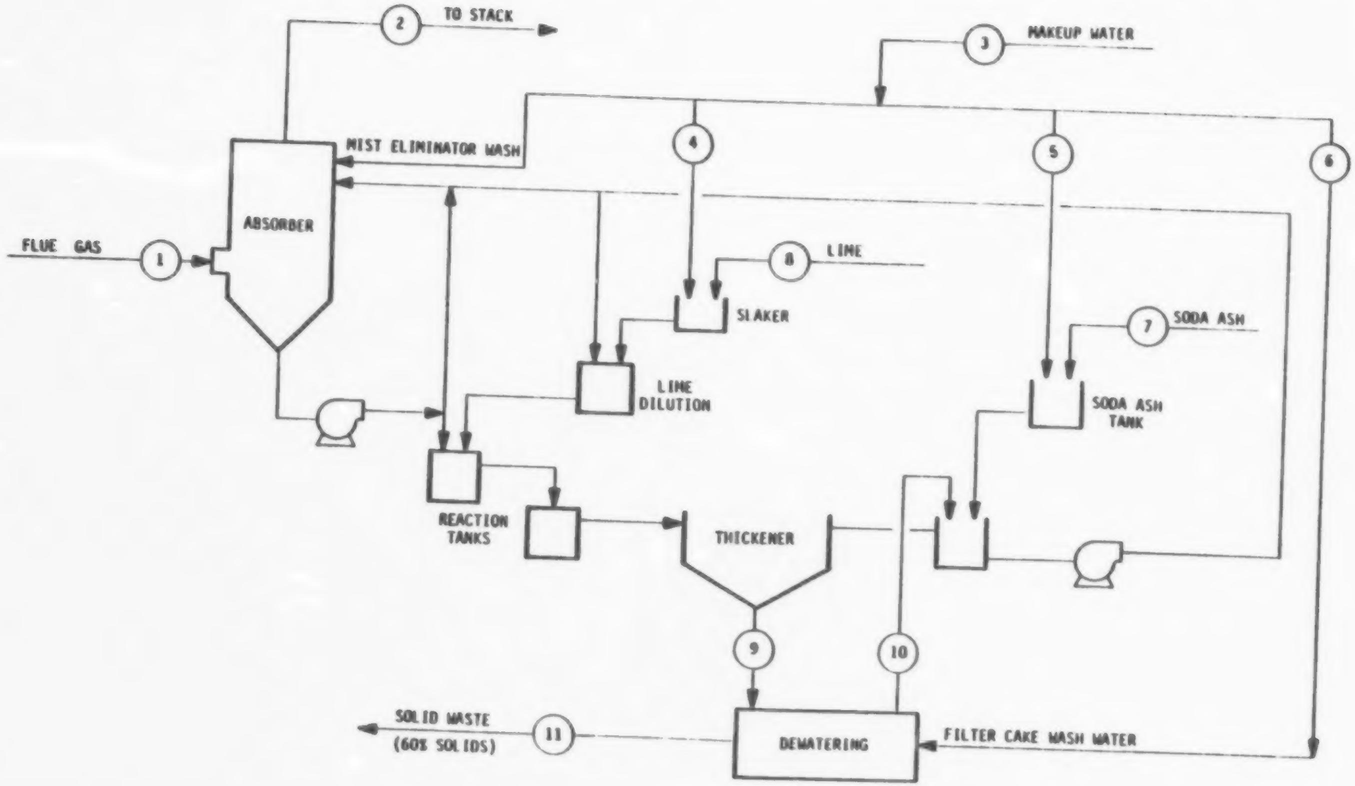
FIGURE E.20 MATERIAL BALANCE FOR LIME SCRUBBING PROCESS (62)


LIMESTONE
CRUSHING & GRINDING
SLURRY TANK
FLUE GAS
1
2
TO STACK
REHEATER
SEAL WATER
3
MAKEUP WATER
4
REACTION TANK
SOLID/LIQUID SEPARATOR
5
SOLIDS DEWATERING
6
SOLID WASTE
7
LIQUOR RETURN

NOTE:
W/O F.O. = WITHOUT FORCED OXIDATION
W/ F.O. = WITH FORCED OXIDATION

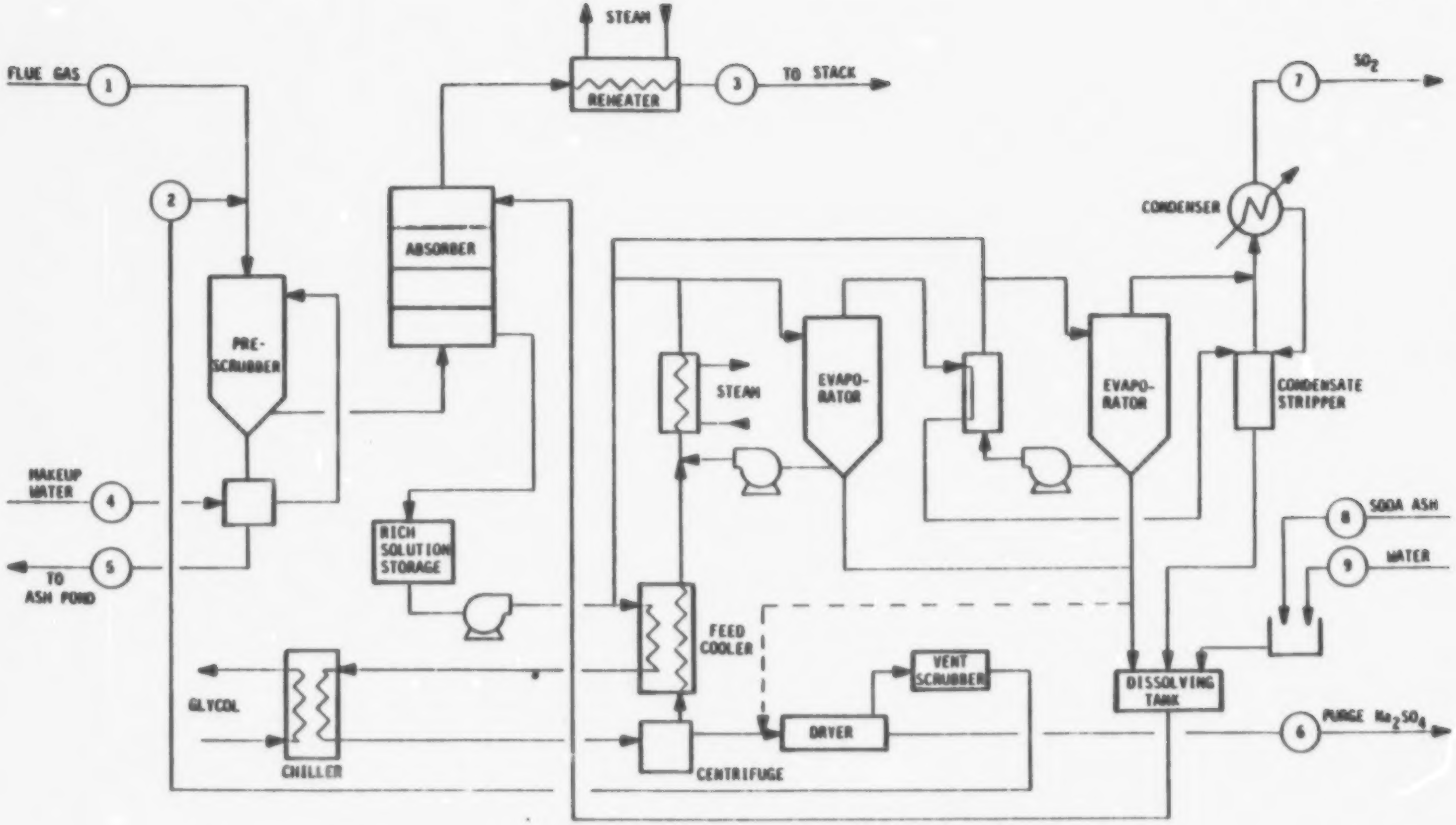
FGD Mode	STREAM 1			2		3	4		5		6		7
	Gasflow (Nm³/min)	Sulphur (kg/min)	Water (kg/min)	Sulphur (kg/min)	Water (kg/min)	Water (kg/min)	Limestone (95% $CaCO_3$) (kg/min)	Water (kg/min)	Solids (kg/min as $CaCO_3$ & hydrated $CaSO_x$)	Water (kg/min including H_2O of Hydration)	Solids (kg/min as $CaCO_3$ hydrated $CaSO_x$)	Water (kg/min including H_2O of hydration)	Water (kg/min)
W/O F.O.	25,250	52	1,739	10	3,282	1,698	158	293	207	501	207	155	346
W/ F.O.	25,250	52	1,739	10	3,282	1,646	158	293	247	617	247	103	514

FIGURE E.21 MATERIAL BALANCE FOR LIMESTONE SCRUBBING PROCESS (62)


FLUE GAS
1
ABSORBER
2
TO STACK
MIST ELIMINATOR WASH
3
MAKEUP WATER
4
5
6
8
LIME
SLAKER
LIME DILUTION
REACTION TANKS
THICKENER
7
SODA ASH
SODA ASH TANK
9
10
DEWATERING
FILTER CAKE WASH WATER
11
SOLID WASTE
(60% SOLIDS)

STREAM															
1			2		3	4	5	6	7	8	9		10	11	
Gasflow (Nm³/min)	Sulphur (kg/min)	Water (kg/min)	Sulphur (kg/min)	Water (kg/min)	Water (kg/min)	Water (kg/min)	Water (kg/min)	Water (kg/min)	Soda Ash (kg/min)	Lime 95% CaO (kg/min)	Solids (kg/min $CaCO_3$ & Hydrated $CaSO_x$)	Water (kg/min)	Water (kg/min)	Solids (kg/min $CaCO_3$ & Hydrated $CaSO_x$)	Water (kg/min)
22,250	52	1,739	10	3,282	1,685	220	28	250	7	80	187	454	313	187	141

FIGURE E.22 MATERIAL BALANCE FOR DUAL-ALKALI SCRUBBING PROCESS (62)


FLUE GAS
1
2
3
TO STACK
STEAM
REHEATER
ABSORBER
PRE-SCRUBBER
MAKEUP WATER
4
5
TO ASH POND
RICH SOLUTION STORAGE
GLYCOL
CHILLER
STEAM
FEED COOLER
CENTRIFUGE
EVAPO-RATOR
EVAPO-RATOR
DRYER
VENT SCRUBBER
CONDENSER
CONDENSATE STRIPPER
7
SO_2
8
SODA ASH
9
WATER
DISSOLVING TANK
6
PURGE Na_2SO_4

STREAM															
1			2		3		4	5		6	7		8	9
Gasflow (Nm³/min)	Sulphur (kg/min)	Water (kg/min)	Gasflow (Nm³/min)	Water (kg/min)	Sulphur (kg/min)	Water (kg/min)	Water (kg/min)	Solids (kg/min)	Water (kg/min)	Solids (kg/min)	SO_2 (kg/min)	Water (kg/min)	N_2CO_3 (kg/min)	Water (kg/min)
22,250	52	1,739	330	12	10	3,294	1,543	1.7	33	18	75	8	14	54

FIGURE E.23 MATERIAL BALANCE FOR WELLMAN-LORD PROCESS (62)

concentrations, or to control excess water in the system (e.g., forced oxidation limestone). Process wastewater is not generated from the FGD spray dryer system, which produces a dry waste product from the scrubber.

The quantities of direct wastewater discharge that might be produced annually from upset conditions at a wet FGD installation are difficult to estimate. It can be expected that volumes generated during such conditions would be smaller than the annual blowdown volumes from a Wellman-Lord process. Based on the total wastewater release rates (41 kg/min) indicated in Figure E.23 for a Wellman-Lord system at a 500-MW station, such a system at a 1000-MW station would generate a wastewater volume of 43 000 m^3/a. A rough approximation of the range of direct wastewater discharge volumes that might be expected from FGD at a 1000-MW facility is 0-43 100 m^3/a.

Because of the very large areas required by some non-regenerable FGD systems for the disposal of sludges, the largest wastewater volumes may well be runoff and seepage from the disposal area. As indicated in Table E.37 FGD sludge volumes at a station burning a low sulphur, low heating value, high ash content coal, add only marginally to the station's already large solid waste production volume. However, with higher sulphur, low ash coals, the FGD system may produce substantially more solid waste in absolute terms and increase the station's total solid waste production by two to four times.

Runoff and seepage volumes would tend to increase proportionally but would depend on many factors, including disposal method (dry landfill versus lagoon), sludge characteristics and permeability of underlying soils. Since the sludge volumes generated with a high sulphur coal can be as much as half the total ash production volumes at a station with low sulphur, poor quality coal, a rough approximation of the upper range of probable runoff and seepage volumes would be half the high values estimated for ash disposal. For a 1000-MW station, the range for FGD related seepage and runoff wastewaters would be:

- 0-750 000 m^3/a seepage
- 0-120 000 m^3/a runoff

The characteristics of FGD related wastewaters can also be highly variable depending on type of system, coal characteristics and source of the waste stream. The process water characteristics shown in Table E.38 provide an indication of the quality of wastewater overflow that might be expected during upset conditions with a wet FGD system. The data presented are from lime (Bruce Mansfield G.S. and Cane Run G.S.) and

TABLE E. 38 CHARACTERIZATION OF FGD SYSTEM WATER STREAMS (63)

Parameter	Bruce Mansfield Generating Station Overflow (lime)	Cane Run Generating Station (Lime)		Dallman Generating Station (Limestone)		
		Makeup	Overflow	Makeup	Return	Overflow
pH	2.4	N/A	12.0	2.3	2.3	2.7
Sp. Conductance (µ mhos/cm)	8 500	N/A	2 950	2 300	7 100	11 100
Total Solids (mg/L)	N/A	N/A	N/A	537	6 680	17 300
Total Suspended Solids (mg/L)	N/A	N/A	22	125	673	2 502
Total Dissolved Solids (mg/L)	N/A	N/A	N/A	412	6 000	14 800
Turbidity (N.T.U.)	N/A	N/A	0.05	0.2	0.3	0.9
Chemical Oxygen Demand (mg/L)	N/A	N/A	118	< 1	880	1 280
"OH" Alkalinity as $CaCO_3$ (mg/L)	N/A	N/A	920	0	0	0
Sulphate as SO_4 (mg/L)	2 260	50	75.5	55	1 009	770
Sulphite as SO_3 (mg/L)	< 1	N/A	11.1	< 1	< 1	550
Chloride (mg/L)	635	162	264	38	1 330	2 830
Fluoride (mg/L)	6.7	< 1	< 1	1.1	46	172
Orthophosphate as PO_4 (mg/L)	< 1	N/A	N/A	< 1	< 1	1.6
Aluminum (mg/L)	1.22	1.79	4.10	0.09	< 0.05	0.33
Arsenic (mg/L)	0.59	0.005	< 0.001	< 0.001	0.006	0.110
Barium (mg/L)	0.077	< 0.005	< 0.005	0.09	< 0.05	0.33
Beryllium (mg/L)	0.0023	< 0.0005	< 0.005	0.008	< 0.0005	< 0.0005
Boron (mg/L)	6.45	3.5	5.85	0.6	116	206
Cadmium (mg/L)	0.04	0.03		0.03	0.07	
Calcium (mg/L)	77.8	416	409	61.7	904	2 900
Cobalt (mg/L)	< 0.05	0.07	0.06	1.41	< 0.05	0.96
Chromium (mg/L)	< 0.01	0.01	< 0.01	6	70	0.04
Copper (mg/L)	0.016	0.021	0.009	0.13	0.06	0.24
Iron (mg/L)	0.88	0.15	0.33	0.06	1.4	49.4
Lead (mg/L)	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	0.05
Lithium (mg/L)	1.4	< 0.1	0.2	< 0.1	0.1	0.3
Magnesium (mg/L)	927	0.12	0.08	25.1	216	528
Manganese (mg/L)	0.02	< 0.01	< 0.01	0.15	9.97	23.0
Mercury (µ g/L)	0.6	< 0.01	< 0.01	< 0.01	1.4	2.9
Molybdenum (mg/L)	1.1	0.4	0.4	1.54	0.14	0.15
Nickel (mg/L)	0.17	0.11	0.14	0.50	0.36	1.40
Phosphorus (mg/L)	2.1	1.4	1.5	0.9	1.5	2.9
Potassium (mg/L)	0.64	21	29	20	11	40
Selenium (mg/L)	0.19	0.01	< 0.01	< 0.003	0.90	1.45
Silica	20.1	2.80	2.80	1.44	30.9	57.3
Silver (mg/L)	< 0.005	< 0.005	< 0.005	0.114	< 0.005	< 0.005
Sodium (mg/L)	75	36	31	26	60	165
Strontium mg/L)	0.109	0.147	0.162	0.09	1.12	2.85
Thorium (µ g/ml)	< 10	0.0002	0.0002	0.68	< 0.05	< 0.05
Titanium (mg/L)	0.040	< 0.005	< 0.005	0.07	< 0.05	0.016
Uranium (µ g/mL)	N/A	0.001	0.001	0.002	0.012	0.002
Vanadium (mg/L)	< 0.005	0.017	0.015	0.16	< 0.05	< 0.05
Zinc (mg/L)	0.08	0.05	0.11	0.11	0.96	7.63
Zirconium (mg/L)	< 0.05	< 0.05	< 0.05	0.17	< 0.05	0.14

Note: All Analyses in mg/L unless otherwise stated.
N/A = Not Analyzed.

limestone with forced oxidation (Dallman G.S.) FGD systems (63). These wastewaters tend to have high dissolved solids, sulphate and chlorine contents. Some also have elevated levels of trace contaminants such as aluminum, boron, molybdenum, nickel and arsenic.

Runoff and seepage characteristics depend on the characteristics of the waste, which in turn depends on the coal, FGD process and the waste stabilization or fixation processes, if any. Table E.39 lists chemical characteristics of sludges from the three systems listed above and an additional limestone system (Marion G.S.). Varying fractions of the constituents listed may leach from the sludges into runoff and/or seepage.

(d) Solid Radioactive Waste Storage. Solid radioactive wastes are generated during station operations. The irradiated fuel bundles from the reactor are stored and cooled within the station. Other radioactive solid wastes are stored in a facility outside the station building. This storage facility may be within the station site boundaries or may be used by a number of different stations.

Solid wastes comprise spent ion exchange resins and cartridge filters associated with the purification of radioactive liquids, and solidified liquid waste and contaminated equipment components, piping tools, rags, clothing, etc. A typical process water purification system is shown in Figure E.24. The spent resins and filters are transported to the solid waste storage facility in shielding flasks. Some of the other solid waste may be compacted or incinerated (if combustible) for volume reduction. Typical solid waste characteristics for a 600-MW(e) CANDU are shown in Table E.40 (1).

The volumetric and isotopic characteristics of seepage and runoff from radioactive solid waste storage facilities depend on the precipitation event characteristics, the area of the site, soil permeability and the designed containment integrity of the storage facilities and the site. No data are readily available for these wastewaters.

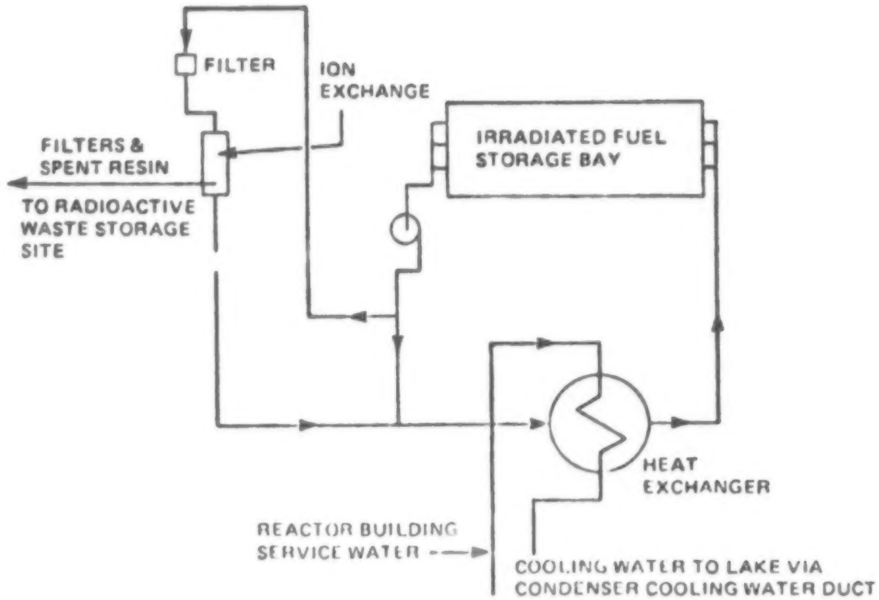
E.2.5 Combined Waste Streams (Fossil and Nuclear). In the foregoing sections, a few of the waste streams identified were not quantified or characterized because the data available and system of wastewater management make it more appropriate to describe them in combination with other streams. Wastes in this category are commonly combined in sumps or holding tanks within the station.

A system of drains and sumps is normally installed in a power plant to collect leaks, spills and general plant cleaning wastewater (See Sections E.2.8 and E.2.9). Sumps or holding tanks are usually strategically located within the plant to contain wastewaters

TABLE E.39 CHARACTERIZATION OF DEWATERED FGD SLUDGES (63)

Parameter	Cane Run Generating Station	Dallman Generating Station	Marion Generating Station	Newton Generating Station
Moisture Content (%)	36.4	34.8	22.6	29.9
Sulphate as SO_4	61 200	485 000	349 000	180 000
Sulphite as SO_3	356 000	179 000	250 000	336 000
Chloride	< 1 000	1 000	2 000	5 000
Phosphate as P_2O_5	2 000	2 000	1 000	2 000
Aluminum	39 600	1 020	34 900	40 600
Arsenic	< 100	< 100	< 100	< 100
Barium	430	< 100	< 100	< 100
Beryllium	2.80	0.02	1.31	1.49
Cadmium	5.5	7	5	1
Calcium	178 000	288 000	230 000	250 000
Cobalt	< 5	60	64	< 5
Chromium	340	10	70	30
Copper	36	8	24	17
Iron	37 100	< 100	26 000	23 800
Lead	< 10	< 10	< 10	< 10
Magnesium	3 880	855	12 200	12 100
Manganese	120	39	220	210
Mercury	310	150	< 100	< 100
Molybdenum	60	60	< 3	< 3
Nickel	44	84	30	< 10
Phosphorus	350	230	380	230
Potassium	7 600	930	6 840	7 560
Selenium	< 1 000	< 1 000	< 1 000	< 1 000
Silica	70 600	10 300	51 400	56 100
Silver	< 0.5	0.3	< 0.3	< 0.3
Sodium	1 800	600	2 500	2 200
Strontium	73	7	160	150
Thorium	< 1	< 1	< 3	< 3
Titanium	11 500	1 400	2 400	600
Uranium	N/A		N/A	N/A
Vanadium	82	7	78	53
Zinc	320	< 10	< 10	< 10
Zirconium	67	12	96	96

Note: All analyses reported in mg/kg unless specified otherwise.
N/A = Not analyzed.


FILTER
ION EXCHANGE
IRRADIATED FUEL STORAGE BAY
FILTERS & SPENT RESIN
TO RADIOACTIVE WASTE STORAGE SITE
HEAT EXCHANGER
REACTOR BUILDING SERVICE WATER
COOLING WATER TO LAKE VIA CONDENSER COOLING WATER DUCT

IRRADIATED FUEL BAY FACILITY COOLING AND PURIFICATIONS SYSTEMS SIMPLIFIED FLOW DIAGRAM

FIGURE E.24 TYPICAL PROCESS WATER PURIFICATION SYSTEM (1) (Shown for Irradiated Fuel Bay Cooling Circuit)

TABLE E.40 SOLID WASTE CHARACTERISTICS FROM A CANDU 600-MW(e) SYSTEM (1)

Category of Waste Solids	Volume (m^3/annum)	Activity (TBq/annum)*
Low-level solid	300	0.2
Ion-exchange resin	15	37.0
Primary coolant filters	5	18.5

* Excludes tritium

from the floor and equipment drains. In some cases, a number of individual sumps discharge directly to the cooling water or local receiving waters. They may or may not undergo oil separation or other treatment prior to discharge (12). In other cases, wastewaters collected in a number of individual sumps in the turbine house, boiler house and other locations in the plant are pumped to a larger central sump where oil separation or other treatment is conducted before release (5). Other wastewaters such as boiler blowdown waters in coal-fuelled stations may also be routed to the central sump and combined with the floor and equipment drain wastewaters.

In nuclear stations, as indicated in Section E.2.2 (c), various radioactive liquid wastes may be routed to the heavy water upgrader if the D_2O isotopic composition is high enough or, more commonly, to the active liquid waste handling tanks prior to discharge from the station. Typical active waste handling systems are shown in Figure E.25 (1). Chemical wastes may be collected and treated separately (typically neutralized). High activity and low activity wastes may be segregated and held for natural radioactive decay and/or treatment prior to discharge from the station (1).

The volumes of wastewater generated solely from periodic floor cleaning, miscellaneous equipment surface cleanings and general "household" cleaning have not been well documented. Available data (12) suggest that these wastewaters are typically about 20 m^3/a•MW, but range from less than 1 m^3/a•MW to 530 m^3/a•MW. At stations where other wastewaters, such as ash hopper cooling water at a coal-fired station, are also directed to a central sump, the wastewater volumes may be larger and make up the majority of the total sump discharge. At one station where both boiler blowdown and ash hopper cooling water are directed to a central sump, these sources reportedly make up about 14 and 83 percent respectively of the sump discharge. The estimated average sump discharge of 3700 m^3/a•MW probably represents the upper range of wastewater volumes

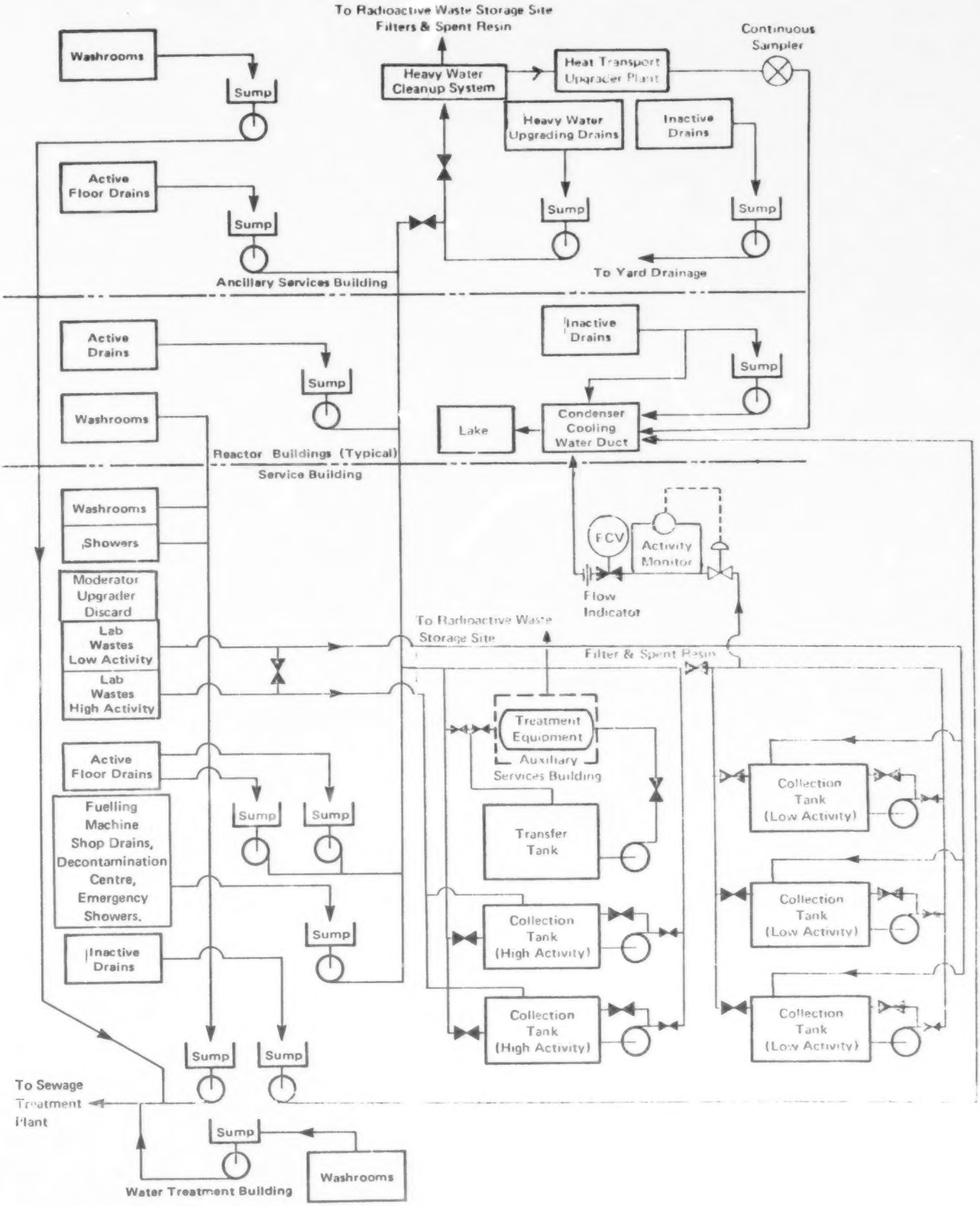

To Radioactive Waste Storage Site
Filters & Spent Resin
Continuous Sampler
Washrooms
Sump
Heavy Water Cleanup System
Heat Transport Upgrader Plant
Heavy Water Upgrading Drains
Inactive Drains
Active Floor Drains
Sump
Sump
Sump
To Yard Drainage
Ancillary Services Building
Active Drains
Inactive Drains
Sump
Sump
Washrooms
Lake
Condenser Cooling Water Duct
Reactor Buildings (Typical)
Service Building
Washrooms
Showers
FCV
Activity Monitor
Moderator Upgrader Discard
Flow Indicator
Lab Wastes Low Activity
To Radioactive Waste Storage Site
Filter & Spent Resin
Lab Wastes High Activity
Treatment Equipment
Auxiliary Services Building
Active Floor Drains
Collection Tank (Low Activity)
Fuelling Machine Shop Drains, Decontamination Centre, Emergency Showers.
Sump
Sump
Transfer Tank
Collection Tank (Low Activity)
Collection Tank (High Activity)
Sump
Inactive Drains
Collection Tank (High Activity)
Collection Tank (Low Activity)
Sump
Sump
To Sewage Treatment Plant
Sump
Washrooms
Water Treatment Building

FIGURE E.25 ACTIVE LIQUID WASTE HANDLING FOR A CANDU NUCLEAR STATION (1)

from power plant drains and sumps. Only three percent, or about 105 $m^3/a \cdot MW$, comes from the floor and equipment drains (5).

To present some data on radioactive wastewaters discharged from nuclear stations, a number of information sources were used and calculations made using available data. The results are shown in Table E.41 (1). Flow data for a 2 000-MW(e) station and estimated flow for a 600 MW(e) station are presented. Average annual activity releases (not including tritium) were calculated from reported annual data for a 2 000 MW(e) and a 3 000 MW(e) facility. Available flow and activity release data for smaller and older nuclear facilities were not used as they are not typical of present CANDU designs.

The isotopic data presented are derived from data reported for a 2 000-MW(e) CANDU. The "estimated relative abundances of the principal gamma emitting radionuclides" (in the active liquid waste hold-up and dispersal tanks) on a monthly basis were tabulated and assumed to be a percentage of the total gross beta-gamma activity for the radionuclides reported. In Table E.41 the maximum percent reported is presented. The minimum percent reported for all radionuclides shown is zero. Thus, the maximum monthly release for the various radionuclides shown in Table E.41 was calculated by multiplying the percent contribution of a radionuclide by the gross beta-gamma activity released for that month. The data provide an indication of the maximum isotopic release rates for the radionuclides reported.

From the data in Table E.41, it is reasonable to assume that the following active liquid waste characteristics might be expected for a generic 1 000-MW(e) CANDU station:-

i)	Volume Discharged	25 000 m^3/annum
ii)	Activity Released	37 GBq/annum gross beta-gamma
iii)	Activity Concentration	1500 Bq/L

No conclusions are drawn from the data reported with respect to the "typical" isotopic composition of the active wastewater discharges, except that it varies quite considerably.

E.3 Wastewater Minimization

Opportunities exist in the design and operation of steam electric stations to minimize the toxic chemicals used for process purposes, and to minimize the toxic characteristics and volume of wastewaters discharged from the station.

TABLE E.41 TYPICAL CHARACTERISTICS OF DISCHARGES FROM ACTIVE LIQUID WASTE TANKS (1)

Station Capacity	Volumes m^3/annum	m^3/MW•annum
2 000 MW(e)	48 000; 52 000	25
600 MW(e)	10 000	17

ACTIVITY RELEASES

Station Capacity	Gross Beta-Gamma GBq/annum (avg.)*	GBq/MWe•annum (avg.)
2 000 MW(e)	7 to 96 (33)	1.7×10^{-2}
3 000 MW(e)	22 to 211 (144)	4.8×10^{-2}

ISOTOPIC CHARACTERISTICS

	Max. Contribution to Gross Beta-Gamma Activity (%)**	Max. Monthly Isotopic Release*** (10^{-2}GBq/month)
Chromium-51	96	1.2
Iron-59	28	0.5
Cobalt-60	70	1.6
Zinc-65	56	1.3
Niobium-95	15	0.1
Zirconium-95	21	0.3
Ruthenium-106	69	5.9
Iodine-131	67	3.1
Cesium-134	51	0.6
Cesium-137	100	2.7
Cerium-141	30	1.1
Cerium-144	59	1.2

* Calculated from reported annual release data.

** Derived from reported monthly isotopic data.

*** Calculated using monthly release data and isotopic "relative contribution" to activity data for 2 000 MW(e) station.

E.3.1 Minimization of Chemical Additives. In order to minimize, and possibly eliminate the use of toxic chemical additives and materials in a specific system, a number of practices could be followed. These include:

- appropriate selection of materials of construction;
- nonchemical methods of controlling biofouling, scaling and/or corrosion;

- evaluation of alternative chemical additives and selection of chemicals with relatively low toxicity concerns;
- monitoring programs to optimize the use of chemicals for scaling, corrosion and biofouling control.

a) Materials of Construction. The corrosion and scaling described in Section D.5.3.(b) for once-through cooling systems can also occur in other power plant systems such as evaporative recirculating cooling systems and ash water transport systems. In some cases, scaling may be controlled by depressing pH (16,64,65). However, at acidic conditions the corrosion tendency of metallic materials will increase. The selection of corrosion resistant materials and galvanically compatible materials in the design phase will minimize the need to add corrosion control chemicals during operation.

The use of asbestos materials for cooling tower components is of environmental and technical concern. Although the evidence that waterborne asbestos is harmful to aquatic life and human health is not conclusive, it has been suggested that "for maximum protection of human health from the potential carcinogenic effects of exposure to asbestos through ingestion of water and contaminated aquatic organisms, the ambient water asbestos concentration should be zero" (65). The detrimental effects of airborne asbestos are well documented and it has been suggested that "asbestos shall not be used in any equipment in such form, manner or location that it can become airborne" (66). Asbestos from cooling tower components could become airborne in the tower drift.

Asbestos cement board has been used in cooling towers for inlet louvres, tower casings, drift eliminators and tower fill. Freezing of asbestos cement board may lead to failure in winter since it expands with retained moisture, and asbestos cement board may also "explode" when contacted by fire. It is also sensitive to pH (minimum pH 5.5) and high chlorides (maximum 1 000 mg/L) (67).

Although a number of non-asbestos based materials are available for construction of cooling towers, environmental and technical considerations discourage the use of asbestos in cooling tower components.

Hexavalent chromium is of particular environmental concern. When chromium-based corrosion inhibitors are used in cooling pond systems, hexavalent chromium may precipitate. This would present a long-term environmental problem with the pond sludge when the station is decommissioned. As a wide variety of other less deleterious but effective corrosion inhibitors are commercially available, the use of chromium chemicals is to be discouraged, particularly for recirculating cooling pond systems.

b) Non-chemical Methods of Scaling, Corrosion and Biofouling Control. A number of techniques that do not involve the use of chemicals are available for the control of scaling, corroson and bioufouling.

Cooling circuit scaling will most probably occur first in the high temperature environment of condensers and heat exchangers. As discussed in Section D.5.3, on-line mechanical condenser tube cleaning systems are used by some power plants for the control of scale and biofouling. Off-line mechanical cleaning of condensers and heat exchanger tubes are also widely used.

In an evaporative recirculating cooling system, fresh make-up water initially routed through the auxiliary heat exchangers will decrease the probability of scaling in this equipment, although scaling may still occur in the main condensers.

Cathodic protection is used for the control of localized galvanic corrosion in cooling systems as described in Section D.5.3. This may be appropriate for intake screens, condenser waterbox/tubesheet and valve/pipe interfaces when corrosive cooling water is used. The two cathodic protection systems are impressed current (which applies an electrical current to the metal being protected) and sacrificial anode (when an expendable metal corrodes preferentially to the metal being protected).

Coatings that contain minute amounts of copper will prevent biological growth on their surfaces. These can be applied to intake screen and pump wells, and stagnant areas in piping where biological growth may occur. However, this technique is not applicable to condenser tubes, where biofouling has the most significant effect from an operational efficiency standpoint.

c) Toxicity of Chemicals. As previously described, a variety of chemicals are used in power plants for biofouling control (see Section D.5.3(a)), for corrosion and scaling control (see Section D.5.3.(b)), for water treatment (see Section E.2.2(a)), for boiler cleaning (see Section E.2.2(d)) and for other purposes.

The toxicity of chemical additives depends on the nature and concentration of the chemical. While some toxics of concern are known, continued research may identify other contaminants of concern in future. It is suggested that the aquatic toxicity of chemical additives be investigated and evaluated if possible prior to their selection for use. Chemical suppliers, environmental agencies and or utility chemicals may be able to provide information.

d) Chemical Minimization Programs. A number of techniques have been reported that can be used in an operating plant to minimize the amounts of chemicals used for control purposes (68). These techniques not only reduce the amounts of chemicals that may require treatment prior to discharge to the environment, but also reduce the operating costs of chemical dosing programs.

Automatic control equipment can be utilized to control dosing rate with respect to pH, conductivity and additive concentrations in the water being treated for process purposes. The effectiveness of the program could be periodically evaluated with

- pre-weighed metal test coupons that are removable on line,
- test heat exchangers maintained at condenser temperatures, in parallel with the main flow,
- frequent water analyses.

Preweighed metal test coupons permit assessment of corrosion rates, both general and local (pitting). An evaluation of fouling conditions can also be obtained. The coupons should be located near the areas of highest bulk temperature in the water (downstream of condenser) (68).

The most severe service area for scaling is at heat exchange surfaces. A test heat exchanger with removable tubes can closely approximate the most severe service conditions in the system. In practice the use of test coupons should be adequate to evaluate the effectiveness of chemical treatment programs between unit shutdowns, and to minimize the chemical doses during operation.

Batch chemical cleaning of condensers and heat exchangers, with appropriate treatment of these wastes, may be more economical in some instances than continuous chemical dosing programs.

RECOMMENDATION R201. For the purposes of controlling biofouling, corrosion and/or scaling in evaporative recirculating cooling systems:

i) chemicals should not be used unless demonstrated to be necessary or to be environmentally innocuous;

ii) asbestos-based materials should not be used for cooling tower components;

iii) chromium chemical additives should not be used for cooling pond recirculating systems;

iv) chemical additive systems (if required) should be designed to minimize the use of chemicals while providing adequate biofouling, silting, corrosion and/or scaling control.

E.3.2 Selection of Power Plant System. The appropriate selection of power plant system designs and operating modes provides opportunities to minimize the amounts of wastewater generated. Systems that provide significant opportunities to minimize wastewater include:

- evaporative recirculating cooling water,
- auxiliary cooling water,
- ash transport, and
- flue gas desulphurization.

a) Evaporative Recirculating Cooling Water. As discussed in Section E.2.1(b), evaporative recirculating systems require either continuous or periodic blowdown to maintain suitable process water quality in the system. The factor that may govern this water quality requirement is scale formation in condenser and heat exchanger tubes. As pure water evaporates from the cooling tower or cooling ponds, scale forming dissolved solids concentrations will increase in the recirculating water with increasing cycles of recirculation.

Figure E.26 illustrates the change in blowdown wastewater flow rates with increased cycles of concentration (i.e., the ratio of recirculating water TDS to make-up water TDS). The curve was calculated assuming a fairly typical three percent evaporation rate and other simplifications. This figure illustrates that there is little incremental reduction in wastewater volumes from evaporative recirculating cooling systems at cycles of concentration greater than two. Water intake volumes will be similarly reduced.

In most cases, depending on make-up water quality, a doubling of scale forming dissolved solids concentrations will not cause scale formation. The depression of the recirculating water pH by the addition of a "simple" acid (e.g., sulphuric) may be required in some cases. It is not expected that more complex scaling/corrosion control would be required in most recirculating cooling systems at two cycles of concentration. If complex additives are used, the blowdown may warrant treatment prior to discharge.

RECOMMENDATION R202. Evaporative recirculating cooling systems should be designed:

i) to operate at a minimum of two cycles of concentration (i.e., the ratio of dissolved solids in the recirculating water to the dissolved solids in the make-up water is greater than two);

ii) so that make-up water is introduced to the system through the auxiliary coolers if practicable.

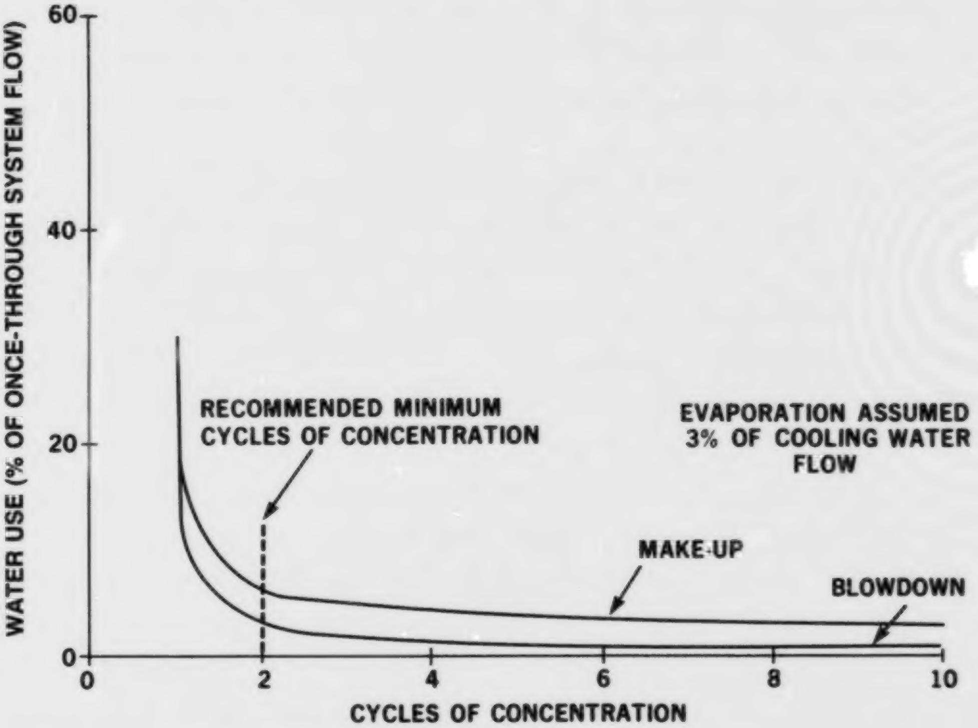


FIGURE E.26 EVAPORATIVE RECIRCULATING COOLING WATER USE

b) Auxiliary Cooling Water. As discussed in Section E.2.1(a), once-through auxiliary cooling systems may become contaminated with the process fluids which are being cooled. If these fluids are at a higher pressure than the once-through cooling water, and there is leakage in the heat exchanger, the cooling water could be uncontrollably contaminated with pollutants such as oil in lubricating oil heat exchangers, or tritium in CANDU moderator heat exchangers. Consequently, discharges from once-through auxiliary cooling systems are classified as Type 2 water (i.e., wastewater).

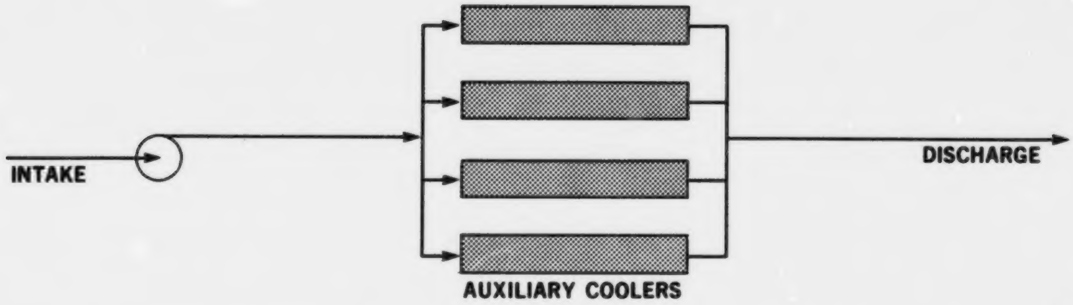
As illustrated in Figure E.27, instead of once-through direct auxiliary cooling systems, an intermediate recirculating loop between the once-through cooling water and the process fluid can be installed. This provides a barrier between the process fluid and the once-through cooling water which is discharged from the generating station. It is unlikely that simultaneous failures would occur in the once-through and process fluid heat exchangers. In any case, the design conditions of the heat exchanger on the once-through side could be selected so that the recirculating water pressure is less than the once-through water pressure. This would completely eliminate the potential for fluid leaks into the once-through water.

Other technical considerations may also influence the decision to use recirculating auxiliary cooling systems. For example, very corrosive seawater or brackish water would cause maintenance problems with once-through auxiliary coolers and affect station reliability. Also once-through cooling water with high dissolved solids concentrations could cause scaling in the auxiliary coolers which are often at higher temperatures than the main condensers.

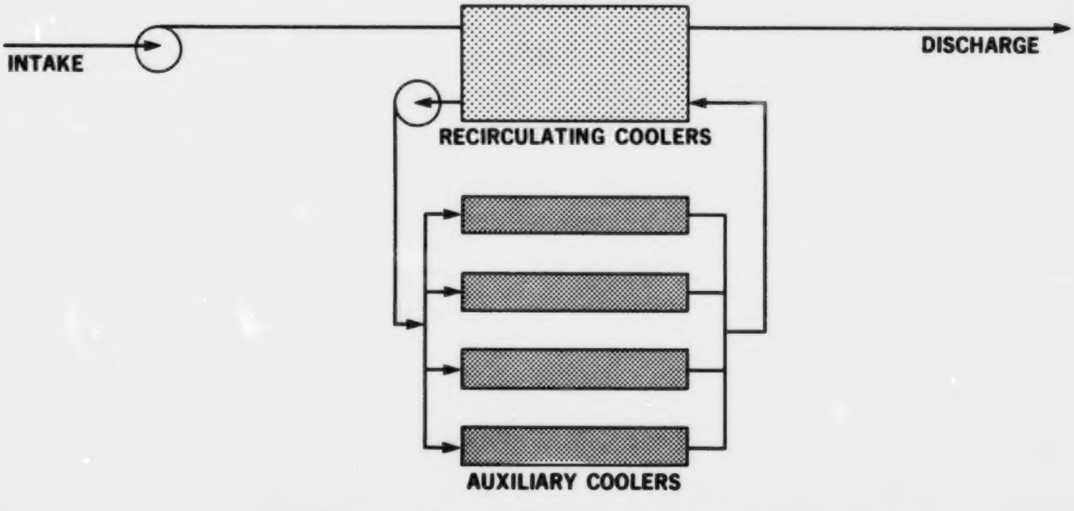
Recirculating auxiliary cooling systems can minimize corrosion or scaling on the once-through side since they can be designed for lower temperatures than direct once-through coolers. Furthermore, the water quality in the recirculating water loop can be closely controlled so that corrosion or scaling will not occur in the auxiliary coolers themselves.

Recirculating auxiliary cooling systems have been installed at a number of generating stations (e.g., Coleson Cove G.S., Dalhousie G.S., Lepreau G.S., Gentilly G.S.) and may be installed in other stations primarily because of reliability considerations (2,69).

Where it is not technically feasible to use intermediate recirculating loop systems, alternatives exist to prevent inadvertent contamination of once-through cooling water. These include early leak detection systems and spare heat exchangers and,


INTAKE
DISCHARGE
AUXILIARY COOLERS

a) SCHEMATIC OF ONCE-THROUGH AUXILIARY COOLING SYSTEM


INTAKE
DISCHARGE
RECIRCULATING COOLERS
AUXILIARY COOLERS

b) SCHEMATIC OF RECIRCULATING AUXILIARY COOLING SYSTEM

FIGURE E.27 ALTERNATIVE AUXILIARY COOLING SYSTEMS

possibly, a positive differential pressure between once-through cooling water and the process fluid.

RECOMMENDATION R203. All auxiliary cooling systems in which the auxiliary cooling water could become contaminated should be intermediate recirculating loop systems (i.e., a closed loop between the once-through cooling water and the auxiliary equipment coolers), or should incorporate another effective method of preventing inadvertent contamination of once-through cooling water.

c) Ash Transport and Disposal. As discussed in Section E.2.4(b), a number of systems can be utilized for the collection, transportation and disposal of bottom ash and fly ash from boilers. As illustrated in Figure E.28 features of these systems include:

i) once-through ash transport water and lagoon disposal;
ii) recirculating ash transport water and lagoon disposal;
iii) separate or combined wet handling of fly ash and bottom ash;
iv) recirculating bottom ash transport water with de-watered ash disposal from settling tanks;
v) dry fly ash transport and disposal;
vi) dry bottom ash transport and disposal.

Recirculating ash transport systems will produce less wastewater than once-through systems. Of course make-up water volumes will also be lower, reducing damage to entrained aquatic organisms.

A recirculating bottom ash system with settling tanks rather than lagoons will provide a comparatively dry product which could be utilized for landfill or other purposes. To maintain suitable process water quality, either blowdown from the recirculating system or side-stream treatment within the system may be required for some ashes. Scaling due to calcium sulphate or calcium carbonate may govern the water quality requirements in alkaline ash transport systems. Generally, fly ash is more likely to cause scaling than bottom ash due to its higher reactivity. Combined fly ash and bottom ash wet systems are more likely to scale than bottom ash systems alone. However, a completely closed ash water system can be designed with side stream softening to reduce scaling forming components (64, 70) (see Section E.5 for treatments). Although ash recirculating transport systems can be designed for zero wastewater discharge, provision for system overflow or blowdown would normally be provided.

The concentration of contaminants leached from the ash will be higher in recirculating ash systems than in once-through systems. Minimizing the blowdown

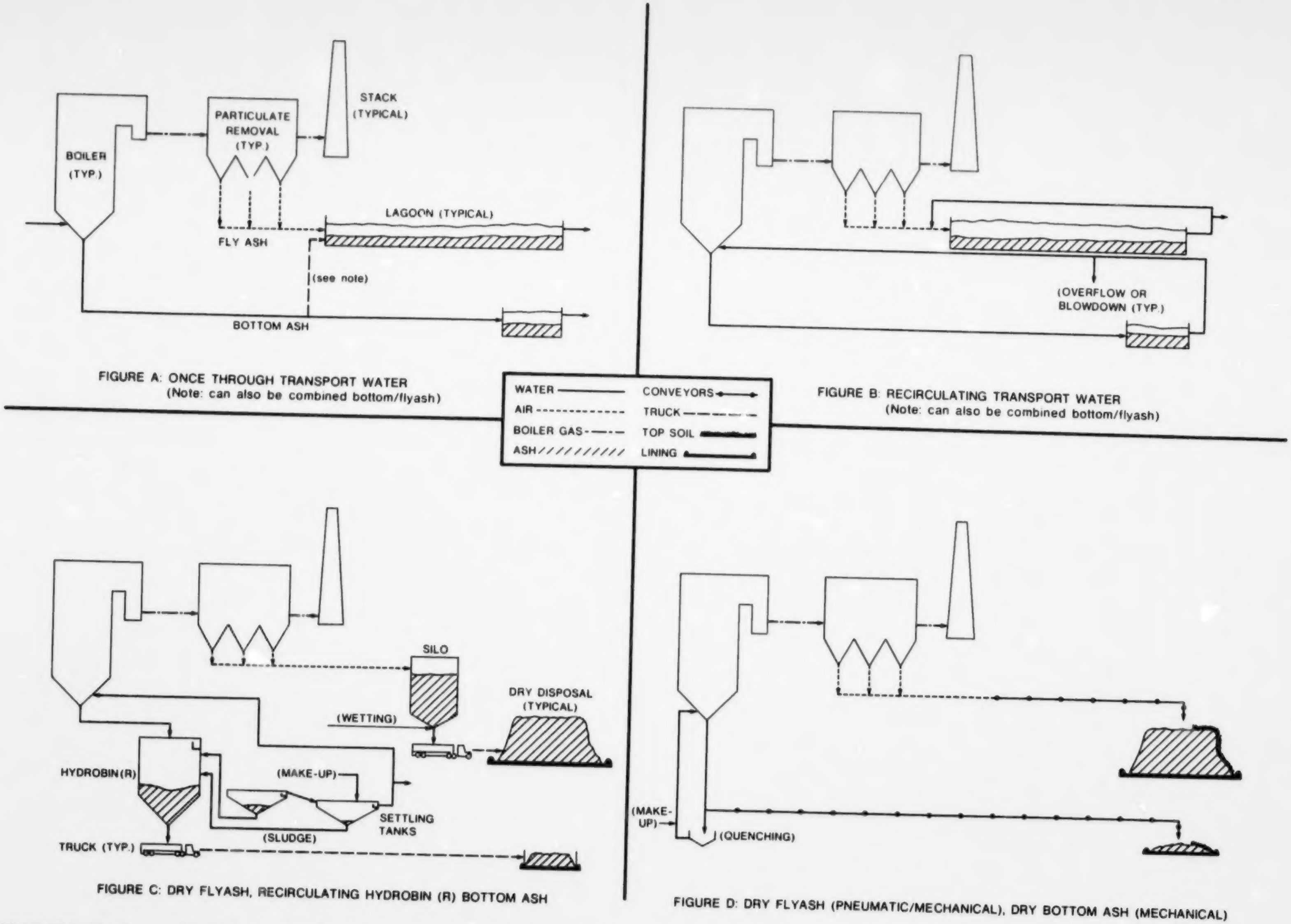

BOILER (TYP.)
PARTICULATE REMOVAL (TYP.)
STACK (TYPICAL)
LAGOON (TYPICAL)
FLY ASH
(see note)
BOTTOM ASH
(OVERFLOW OR BLOWDOWN (TYP.)
WATER
AIR
BOILER GAS
ASH
CONVEYORS
TRUCK
TOP SOIL
LINING
SILO
DRY DISPOSAL (TYPICAL)
(WETTING)
HYDROBIN(R)
(MAKE-UP)
SETTLING TANKS
(SLUDGE)
TRUCK (TYP.)
(MAKE-UP)
(QUENCHING)

FIGURE A: ONCE THROUGH TRANSPORT WATER
(Note: can also be combined bottom/flyash)

FIGURE B: RECIRCULATING TRANSPORT WATER
(Note: can also be combined bottom/flyash)

FIGURE C: DRY FLYASH, RECIRCULATING HYDROBIN (R) BOTTOM ASH

FIGURE D: DRY FLYASH (PNEUMATIC/MECHANICAL), DRY BOTTOM ASH (MECHANICAL)

FIGURE E.28 ALTERNATIVE ASH HANDLING SYSTEMS

volumes will increase these concentrations so that the wastewater streams are more amenable to effective treatment for the removal of contaminants prior to discharge from the generating station. Alkaline ash transport water will tend to precipitate many heavy metals so that treatment prior to discharge, other than solids separation, may not be warranted (71).

Dry fly ash systems are widely utilized (e.g., Sundance G.S., Lakeview G.S., Dalhousie G.S., Lingan G.S.). In these power plants, ash is conveyed pneumatically to a silo and then by truck or conveyor to disposal. The advantages include:

i) no process wastewater;
ii) no scaling or corrosion problems;
iii) potential utilization of fly ash (e.g., for cement or waste sludge conditioning);
iv) less space requirements than wet systems.

Some water is used in these "dry" systems for dust suppression at the fly ash silo unloader and also possibly at the fly ash disposal site. In dry vacuum systems, water may be used to pull vacuum in venturi-type exhausters. This water is normally not contaminated since ash is removed from the air before the vacuum pump. This water can be recirculated to the exhausters or re-used elsewhere.

Mechanical bottom ash transport systems appear to be gaining broader acceptance by Canadian utilities (e.g., Battle River G.S., Lingan G.S Units 3 and 4.). A schematic of this system is presented in Figure E.29. The ash drag flight conveyor equipment and bottom ash hopper is illustrated in Figure E.30 (64). For zero wastewater discharge some treatment of the recirculating ash quench water might be required to prevent scaling.

Ash handling systems tend to require more maintenance than other plant systems. Piping and equipment scaling might occur particularly in wet fly ash or combined systems, in return recirculating lines and in stagnant high temperature areas. Scouring of piping by abrasive bottom ash would tend to reduce scaling but might cause piping wear, particularily at bends. Corrosion of bottom ash piping has occurred in bottom ash recirculating systems in stations where high sulphur eastern Canada coals are used. The performance of ash unloaders and the dust suppression of dry fly ash storage silos has not been consistently satisfactory in all dry ash systems. Freezing of exposed equipment, particularly instrumentation has occurred. In some cases, as with any new system, retrofitted design modifications may be required after initial operating experience identifies problems that were not anticipated during the design phase (70, 72).

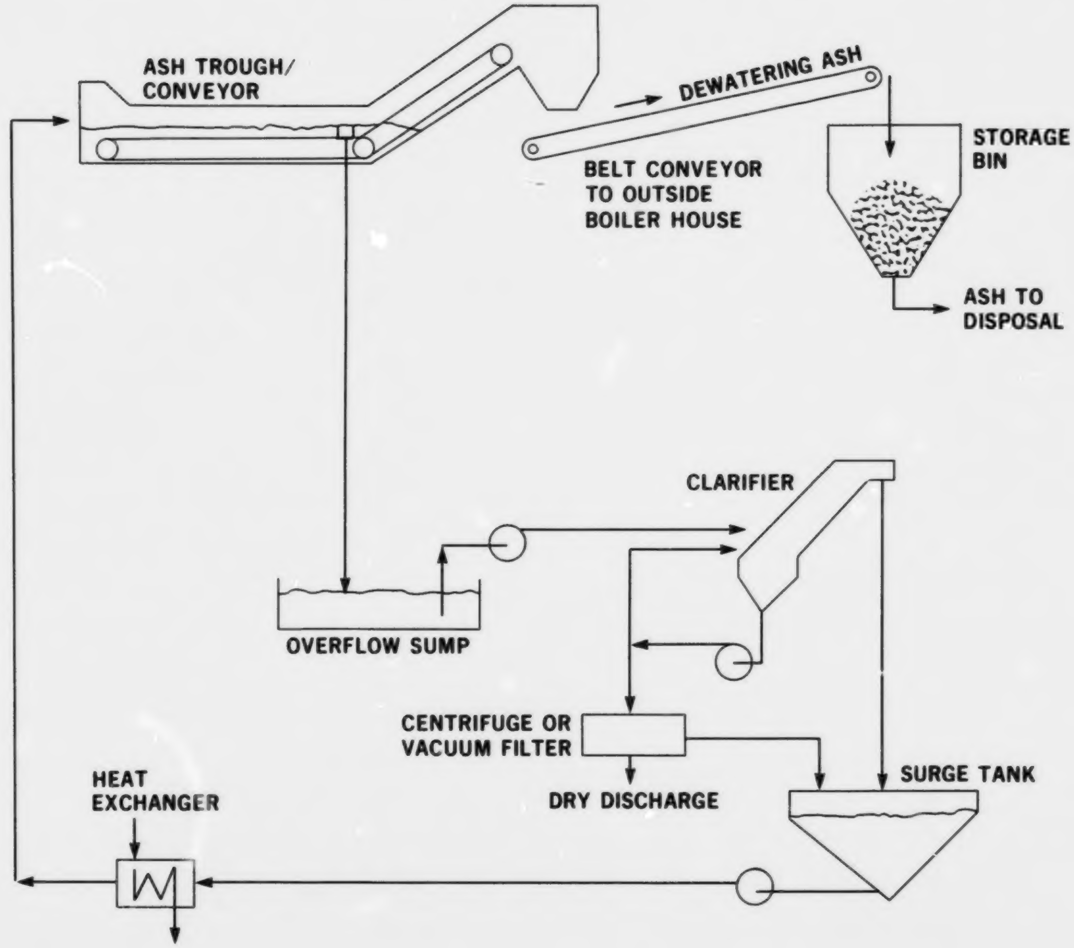

ASH TROUGH/
CONVEYOR
DEWATERING ASH
STORAGE
BIN
BELT CONVEYOR
TO OUTSIDE
BOILER HOUSE
ASH TO
DISPOSAL
CLARIFIER
OVERFLOW SUMP
CENTRIFUGE OR
VACUUM FILTER
DRY DISCHARGE
SURGE TANK
HEAT
EXCHANGER

FIGURE E.29 MECHANICAL BOTTOM ASH SYSTEM SCHEMATIC

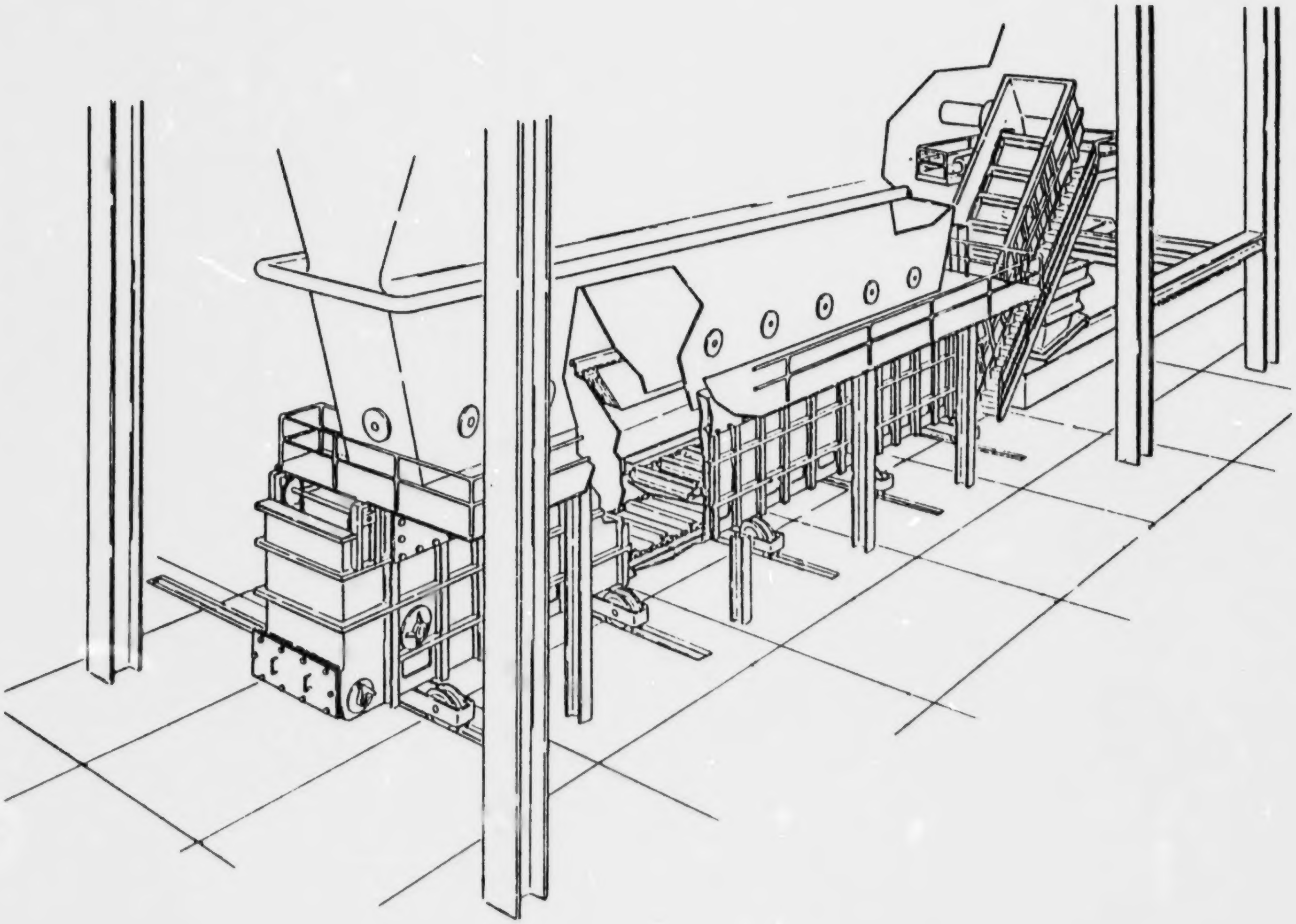


FIGURE E.30 MECHANICAL BOTTOM ASH SYSTEM HOPPER AND CONVEYOR ILLUSTRATION (64)

The reliability of ash handling systems, which greatly affects the station availability, can be increased by appropriate provisions in the design phase. These include:

i) appropriate selection of materials of construction and system design for abrasive service;

ii) provision for chemical control to prevent scaling or corrosion;

iii) redundancy of equipment, particularly pumps (i.e., back-up capacity);

iv) winterization of system by housing major equipment, heat tracing exposed piping, and providing freeze protection for outside instrumentation;

v) minimization of pump seal water requirements.

RECOMMENDATION R204. The selection and design of the ash collection, transport and disposal system for a coal-fuelled station should be a "dry" fly ash system and a "recirculating" bottom ash system, unless it is demonstrated that the total wastewater volumes and contaminants discharged are less for other types of ash systems.

This recommendation precludes the use of once-through ash transport water systems. However, it allows recirculating wet fly ash transport systems if they incorporate zero wastewater discharge. It also allows recirculating combined bottom ash/fly ash systems if the blowdown is equivalent to a bottom ash recirculating system only.

d) Flue Gas Desulphurization (FGD). The formulation of federal guidelines (61) and provincial initiatives has influenced some utilities to consider installation of FGD systems. FGD systems were planned for the Hat Creek G.S. and Lambton G.S., although decreases in electrical load requirements have since led to deferrals of these decisions.

Full-scale operating FGD systems in power plants include the limestone, lime, dual-alkali, Wellman-Lord alkaline fly ash, sodium carbonate and spray dryer systems. Some of these systems are illustrated schematically in Section E.2.4(c).

FGD systems require water primarily for scrubbing liquor and transport of waste sludges generated in the process. Make-up water is required to replace losses due to evaporation in the scrubber and occlusion in the solid waste. Other water losses from the overall system may result from bleed streams, solids drying, entrainment in the product gas stream, and cooling water blowdown associated with some FGD processes. Water use requirements for the spray dryer system are less than for the other FGD systems listed, which all have comparable water requirements (11).

The Wellman-Lord process normally requires a continuous purge from the pre-scrubber loop and also has a cooling water discharge. Limestone, lime, and dual-alkali processes can be designed and operated with no process wastewater discharge (73) as can the "dry" spray dryer process. However, the "wet" FGD systems may require purges during or after excursions from process design conditions. In some specific cases blowdown may be required if chlorides and other dissolved solids concentrate to the point that severe corrosion of materials of construction might occur.

The quantities and chemical/physical characteristics of waste sludges generated in different FGD processes vary. The Wellman-Lord process typically generates only 5-10% of the solid waste produced by the limestone, lime and dual-alkali processes and produces commercial grade sulphuric acid or elemental sulphur. The thixotropic nature of sulphite sludges, which are often produced in "wet" FGD systems, is of environmental concern since the associated sludge disposal areas cannot readily be reclaimed. The transportation and disposal of undewatered sludge (i.e., "ponding") is less common in new FGD waste management systems.

Sludge dewatering with conditioning or fixing, or forced oxidation with dewatering techniques can produce "dry" sludges that are more stable than sulphite sludges produced by many "wet" FGD systems.

Complete utilization of FGD power plant sludges is practiced in Japan (73). A common technique is forced oxidation of calcium sulphite to calcium sulphate which is used in cement or to produce gypsum board. However, forced oxidation may upset the closed loop water balance in the FGD system because of the improved dewatering of the sulphate sludge (73). It may be necessary to wash high chloride sludges to produce a quality suitable for gypsum board. This would also upset the overall water balance, so that, for these systems, a process blowdown may be required.

FGD systems are relatively complex chemical systems which require a high degree of maintenance in comparison to other power plant systems. In "wet" systems, piping and equipment scaling might occur, particularly in mist eliminators if suitable water quality is not used. Corrosion might also occur, particularly in ducts and stacks downstream of the FGD system, because of condensation of acids due to the temperature drop in the system. Chloride corrosion might occur, particularly with high chloride ashes in a pre-scrubber loop. Freezing of exposed equipment, particularly instrumentation has occurred. However, appropriate modifications to the first generation FGD system design have improved their reliability. Design considerations that will improve the reliability of wet FGD systems include:

i) an appreciation of various water quality requirements and sludge characteristics;
ii) appropriate selection of materials of construction for scaling and corrosive services;

iii) redundancy of equipment, particularly pumps and scrubbers (i.e., back up capacity);

iv) provision of surge capacity and drainage within the FGD process in the form of emergency holding tanks, sumps or ponds;

v) winterization of the system by housing major equipment such as pumps, vacuum filters, centrifuges, prescrubbers and scrubbers, and by providing freeze protection for exposed instrumentation and piping.

In addition to these measures, the commitment and cooperation of designers, operators, maintenance staff and utility management appears to be particularly important for the effective and reliable operation of new FGD systems (63).

The spray dryer FGD systems do not appear to have the same potential operating and maintenance problems as "wet" systems because they are relatively simple processes and produce a dry product which is usually wetted for dust suppression. There appears to be a recent tendency by some utilities to select these systems, particularly for low sulphur coals, despite the relatively short history of operating experience. The predicted operating costs may be higher with spray dryer systems for high sulphur coals because of the soda ash or lime reagent costs. However, capital energy and maintenance costs may be lower than the equivalent wet processes (11,74,75). Recent design modifications appear to offer improved reagent utilization (e.g., solids recirculation).

RECOMMENDATION R205. The flue gas desulphurization system for a fossil-fuelled station should be selected or designed for a closed process water loop or equivalent (i.e., no discharge of process wastewaters during normal operation), to the extent practicable.

The intent of this recommendation is to encourage the consideration of FGD process options and additions for waste utilization. If this is not technically or economically desirable, the system should be designed for zero process wastewater discharge, and the sludge should be dewatered, possibly after forced oxidation, or before stabilizaton or fixation prior to disposal. If process blowdown from a system is required, dissolved solids removal techniques can be used prior to reusing (or discharging) the water. This will be effectively a "zero discharge" FGD system (see E.5).

E.3.3 Water Reuse and Zero Wastewater Discharge. As indicated previously, the primary water consuming processes and operations in steam-electric power plants are:

i) cooling water systems (condenser and other equipment);

ii) steam generating system;

iii) general services water systems (pump seals, cleaning and miscellaneous operations);

iv) ash handling system; and
v) flue gas desulphurization system.

The quantities of fresh make-up water required and wastewater discharged depend on the extent to which recirculation and reuse is practiced within a certain size of plant. Water management in power generating stations can range from once-through to "zero" wastewater discharge. In a once-through water management approach, fresh water is used to supply all water requirements, and wastewater flows are equal in volume to the make-up requirement, minus any evaporative losses or losses occluded in solid wastes. Such systems require large quantities of water and can incur high costs associated with water conditioning and wastewater treatment operations, particularly if intake water quality is poor. High volumes of relatively dilute wastewaters make practicable removal of metals and other contaminants difficult, increasing the total contaminants discharged.

Opportunities to select recirculating systems which reuse the same water within a system have been discussed in Section E.3.2. Opportunities also exist to reuse the wastewater discharge from one process as the make-up water to another process that has lower water quality requirements. This "cascade" strategy may reduce pumping and water treatment costs. In addition, the number of entrained species in intake water will be reduced and water will be conserved which may be an important consideration in comparatively arid areas.

Several cascade reuse opportunities are indicated in Table E.42. The reuse of water from one system in another system or systems will depend on the quantities, frequencies and flow rates involved in addition to the chemical characteristics of the water. These are station-specific factors that may be allowed for by the provision of holding ponds between the various systems.

The most obvious technique, in terms of volume and water quality, is to reuse the heated discharge from a once-through freshwater cooling system or the blowdown from an evaporative recirculating cooling system for other plant processes. The blowdown from boilers or steam generators is also of comparatively high water quality which generally can be reused for other processes such as water treatment plant make-up. Progressively decreasing water quality requirements are generally needed for FGD, ash handling and dust suppression services, respectively.

A specific wastewater may require some treatment prior to reuse in another process. Various treatment technologies are discussed in Section E.4. A wastewater treatment system designed to meet certain station effluent criteria may consistently produce water of suitable quality for reuse.

TABLE E.42 WATER/WASTEWATER REUSE POTENTIAL WITHOUT TREATMENT

System Feed / System Discharge	Recirculating Cooling	Water Treatment Plant	Equipment Cleaning	Pump Seals	Firewater	Ash Transport	Flue Gas Desulphurization	Coal Pile Dust Control	Ash Pile Dust Control	FGD Pile Dust Control	
Once-Through Cooling	NA	X	X	X	X	X	X	X	X	X	See Note 1)
Recirculating Cooling	-	X	(X)	0	X	X	X	X	X	X	See Note 1)
Water Treatment Plant	0	-	0	0	0	(X)	0	X	X	X	
Laboratory Drains	0	0	0	0	0	(X)	0	X	X	X	
Boiler/Steam Generator	X	X	X	X	X	X	X	X	X	X	
Roof and Yard Drains	X	X	X	X	X	X	X	X	X	X	
Turbine Floor Drains	(X)	(X)	(X)	0	(X)	X	X	X	X	X	
Boiler Floor Drains	(X)	(X)	(X)	0	(X)	X	(X)	X	X	X	
Equipment Cleaning	0	0	0	0	0	(X)	(X)	X	X	X	
Sewage Treatment Plant	X	X	X	0	0	X	X	X	X	X	
Ash Transport	0	(X)	0	0	0	-	(X)	X	X	X	
Flue Gas Desulphurization	0	0	0	0	0	X	-	X	X	X	
Coal Pile (Runoff)	(X)	(X)	0	0	(X)	(X)	(X)	X	X	X	
Ash Pile (Runoff)	(X)	(X)	0	0	(X)	(X)	(X)	X	X	X	
FGD Pile (Runoff)	(X)	(X)	0	0	(X)	(X)	(X)	X	X	X	

Notes: NA - not applicable
X - discharge may often be re-used
(X) - discharge may seldom be re-used
0 - discharge cannot be re-used without treatment

1) Reuse potential for sea or brackish cooling water is unlikely
2) Reuse potential will depend on quantities, frequencies and flow rates of discharge in addition to site-specific water chemical characteristics and system feed requirements.

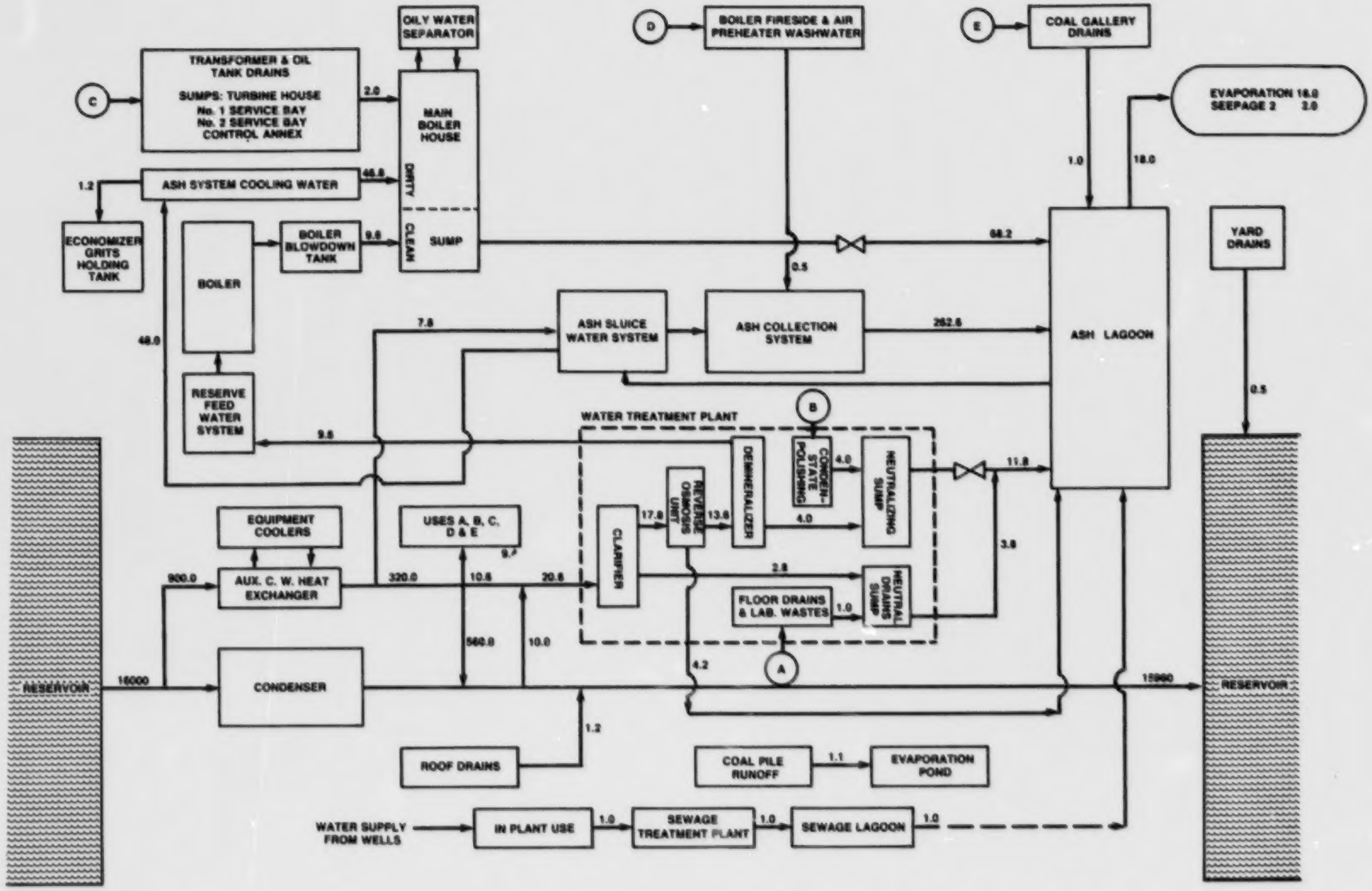
With appropriate collection, segregation, recirculation, reuse, treatment, flow balancing and disposal of the vast water-related inventory of a power plant, a zero wastewater discharge station can be designed and operated successfully. Over 30 zero discharge plants are now operating in the U.S.A. and while most are coal-fired plants they also include nuclear, oil and gas plants. Most are located in the arid west in areas of low water quality and availability, and in areas where net evaporation allows waste sludges to be naturally concentrated in lined lagoons. In many cases they were designed in response to local water quality requirements that specified zero discharge. In other areas of the U.S.A. local effluent criteria were so stringent that the utilities elected to install a zero discharge plant (76). Many examples of zero discharge plants are documented (77-81) and some are discussed in Section E.5.

An example of extensive recirculation and reuse is presented in Figure E.31 which shows the water balance for the Poplar River G.S.. Discharge from the cooling systems is used as feed to the water treatment plant and for ash sluice system makeup, ash hopper cooling and other plant services. Wastewater from the water treatment plant and boiler blowdown is used as makeup in the recirculating ash transport system.

Figure E.32 shows the water schematic for a retrofitted zero wastewater discharge design for a station with a once-through cooling system in an area of net precipitation. Non-contact (i.e., non-contaminated) cooling water and intake screen backwash is segregated and returned to the river. All in-plant wastewaters are collected and clarified. Treated wastewater and coal pile runoff are contained and reused for dust suppression (80).

The water/wastewater management system for the proposed Hat Creek G.S. is designed for zero discharge. As illustrated in the simplified schematic in Figure E.33, treated sewage and boiler blowdown will be routed to the cooling tower makeup. Cooling tower blowdown will be treated by reverse osmosis and used in the water treatment plant feed for recirculating ash system makeup and for periodic coal plant washing. Neutralized water treatment plant wastes will also be used for ash system makeup and for periodic coal plant washing (81).

The operating experience of zero discharge generating stations has not been uniformly satisfactory, particularly for the early designs. An extensive compilation of important factors in the project planning, design, construction, commissioning and operation of zero discharge plants has been made by the U.S. Electric Power Research Institute (EPRI). Effective communication between designers and operators appears to be


C
TRANSFORMER & OIL TANK DRAINS
SUMPS: TURBINE HOUSE
No. 1 SERVICE BAY
No. 2 SERVICE BAY
CONTROL ANNEX
2.0
OILY WATER SEPARATOR
MAIN BOILER HOUSE
DIRTY
CLEAN
SUMP
1.2
ASH SYSTEM COOLING WATER
46.8
ECONOMIZER GRITS HOLDING TANK
BOILER
BOILER BLOWDOWN TANK
9.6
48.0
RESERVE FEED WATER SYSTEM
D
BOILER FIRESIDE & AIR PREHEATER WASHWATER
0.5
E
COAL GALLERY DRAINS
1.0
18.0
EVAPORATION 18.0
SEEPAGE 2 2.0
68.2
ASH LAGOON
YARD DRAINS
0.5
7.8
ASH SLUICE WATER SYSTEM
ASH COLLECTION SYSTEM
262.6
WATER TREATMENT PLANT
B
9.6
DEMINERALIZER
CONDEN-STATE POLISHING
4.0
NEUTRALIZING SUMP
11.8
EQUIPMENT COOLERS
USES A, B, C, D & E
9.4
CLARIFIER
17.8
REVERSE OSMOSIS UNIT
13.6
4.0
3.8
900.0
AUX. C. W. HEAT EXCHANGER
320.0
10.6
20.8
2.8
NEUTRAL DRAINS SUMP
FLOOR DRAINS & LAB. WASTES
1.0
560.0
10.0
4.2
A
RESERVOIR
16000
CONDENSER
15960
RESERVOIR
1.2
ROOF DRAINS
COAL PILE RUNOFF
1.1
EVAPORATION POND
WATER SUPPLY FROM WELLS
IN PLANT USE
1.0
SEWAGE TREATMENT PLANT
1.0
SEWAGE LAGOON
1.0

NOTE: ALL FLOW RATES ARE LITRES/SEC.

FIGURE E.31 WATER MANAGEMENT SCHEMATIC FOR POPLAR RIVER G.S. (5,82,83)

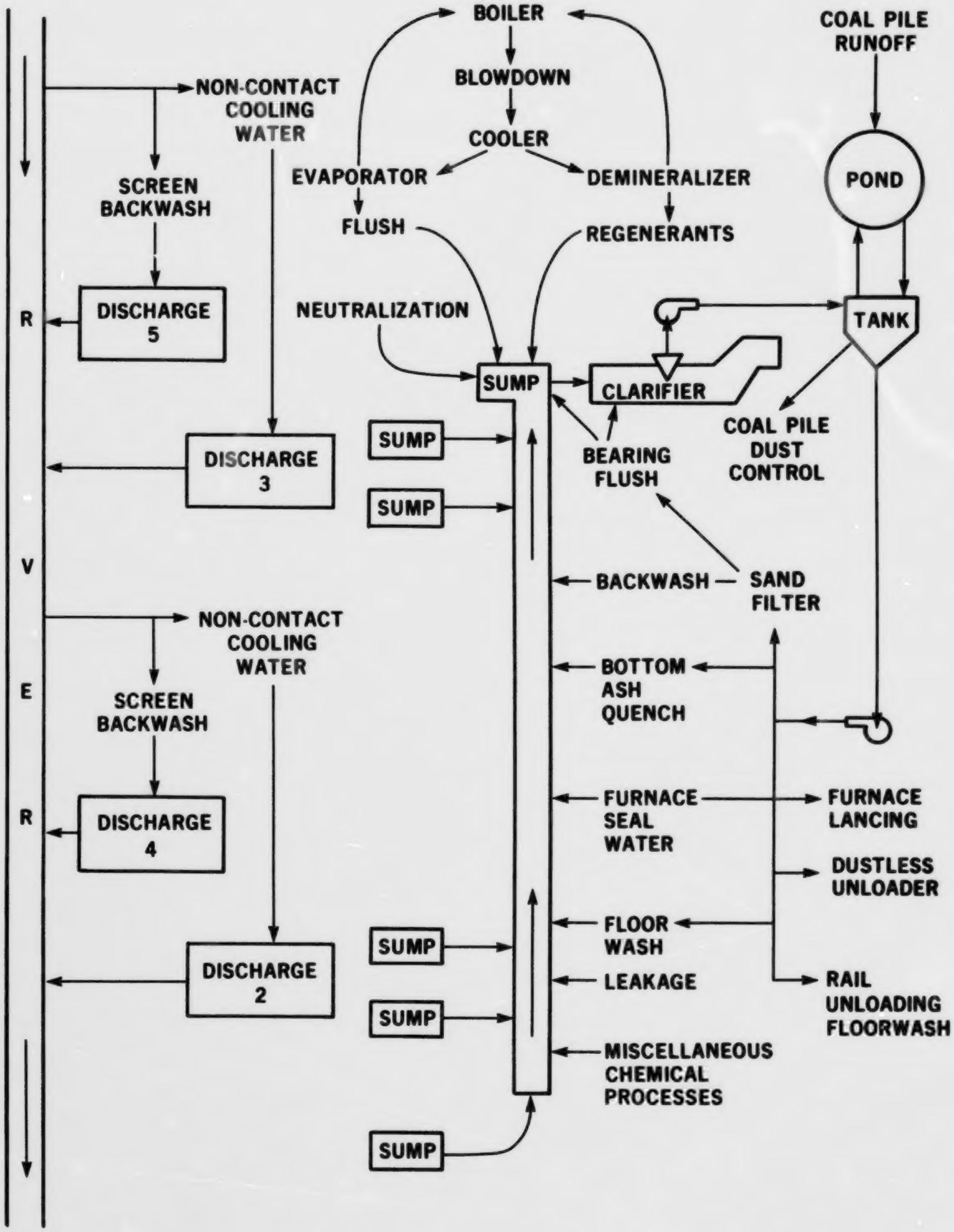
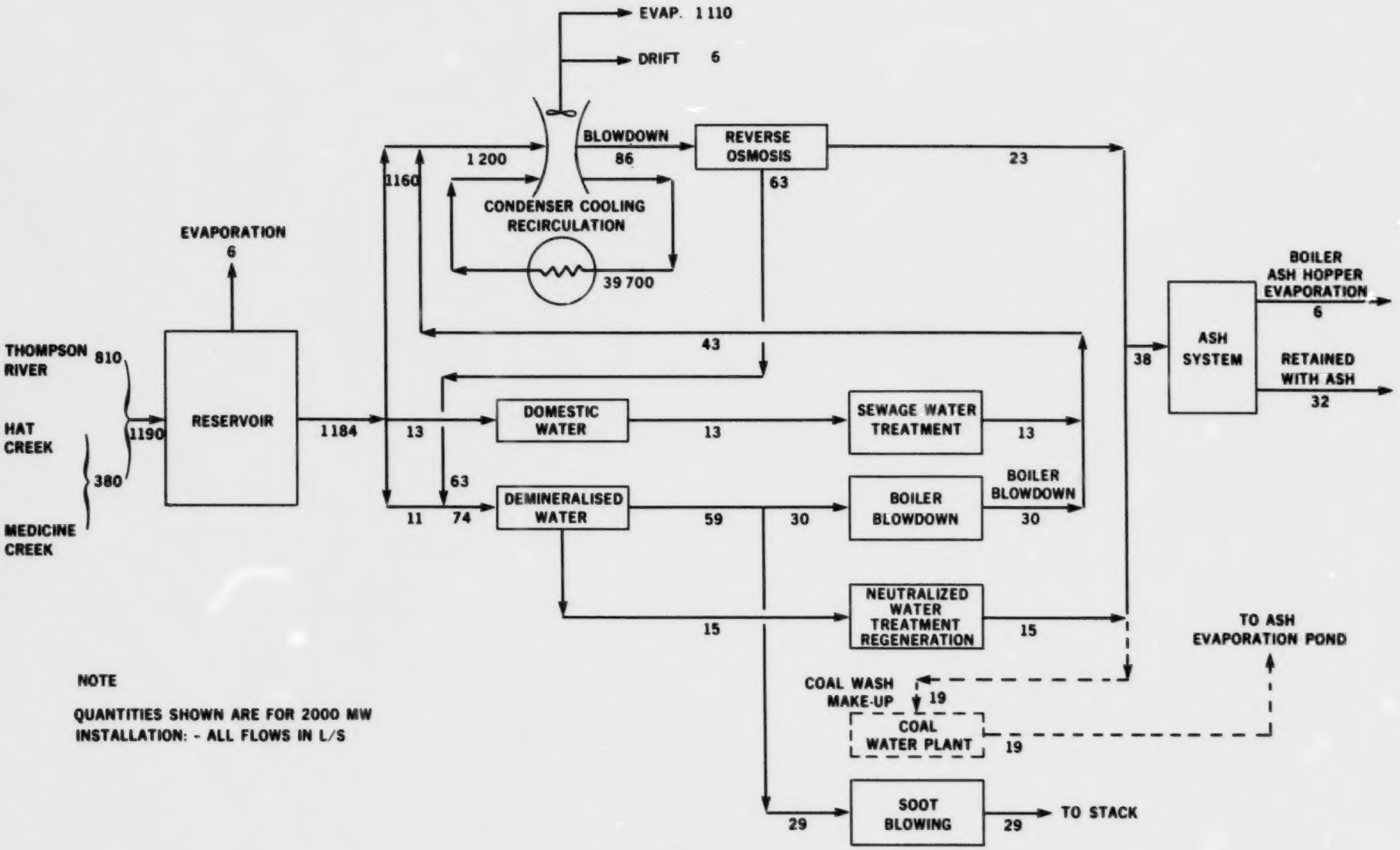

BOILER
BLOWDOWN
COOLER
EVAPORATOR
DEMINERALIZER
FLUSH
REGENERANTS
NEUTRALIZATION
SUMP
CLARIFIER
COAL PILE RUNOFF
POND
TANK
COAL PILE DUST CONTROL
BEARING FLUSH
NON-CONTACT COOLING WATER
SCREEN BACKWASH
DISCHARGE 5
DISCHARGE 3
SUMP
SUMP
RIVER
BACKWASH
SAND FILTER
BOTTOM ASH QUENCH
NON-CONTACT COOLING WATER
SCREEN BACKWASH
DISCHARGE 4
FURNACE SEAL WATER
FURNACE LANCING
DUSTLESS UNLOADER
FLOOR WASH
LEAKAGE
RAIL UNLOADING FLOORWASH
DISCHARGE 2
SUMP
SUMP
MISCELLANEOUS CHEMICAL PROCESSES
SUMP

FIGURE E.32 WATER MANAGEMENT SCHEMATIC FOR HIGH BRIDGE G.S. (80)


EVAP. 1 110
DRIFT 6
BLOWDOWN
86
1 200
REVERSE OSMOSIS
23
63
1160
CONDENSER COOLING RECIRCULATION
39 700
EVAPORATION
6
THOMPSON RIVER
810
HAT CREEK
1190
380
MEDICINE CREEK
RESERVOIR
1184
43
13
DOMESTIC WATER
13
SEWAGE WATER TREATMENT
13
63
11
74
DEMINERALISED WATER
59
30
BOILER BLOWDOWN
BOILER BLOWDOWN
30
15
NEUTRALIZED WATER TREATMENT REGENERATION
15
38
ASH SYSTEM
BOILER ASH HOPPER EVAPORATION
6
RETAINED WITH ASH
32
TO ASH EVAPORATION POND
COAL WASH MAKE-UP
19
COAL WATER PLANT
19
29
SOOT BLOWING
29
TO STACK

NOTE

QUANTITIES SHOWN ARE FOR 2000 MW INSTALLATION: - ALL FLOWS IN L/S

FIGURE E.33 WATER MANAGEMENT SCHEMATIC FOR HAT CREEK G.S. (81)

particularly important. The sensitivity of the water balance and chemistry has upset many systems because of differences in design and actual operating conditions.

Design considerations suggested for reliable performance of zero discharge plants include:

i) an integrated water/wastewater systems approach;
ii) appropriate segregation of waters;
iii) adequate storage and surge capacity;
iv) redundancy of important equipment;
v) accurate estimations of cooling tower blowdown flows, ash system feed and overflows, FGD make-up and blowdown flows;
vi) adequate provision for flow monitoring;
vii) reliable water chemistry data; and
viii) selection of reliable sump pumps with appropriate materials of construction.

The appropriate training of operating and maintenance personnel is also of importance since water/wastewater systems generally do not tend to be given a high priority by generating station staff, whose primary objective is to produce electricity (77).

The more recent adequately designed and operated zero discharge plants have performed very reliably. A good example of this is the Ray D. Nixon G.S. in Colorado which is also discussed in Section E.5.

RECOMMENDATION R206. Wherever it is practicable to do so, process or service water should be supplied by withdrawal from the condenser or auxiliary cooling water discharge, and/or by the reuse of untreated or treated station wastewater streams.

E.3.4 Minimization of Runoff and Seepage from Solid Fuel Storage and Waste Disposal Areas. Steam electric stations may produce solid wastes that require long term disposal or interim storage. These wastes include:

i) fly ash and bottom ash,
ii) flue gas desulphurization sludges, and
iii) low and medium level radioactive wastes.

Containment provisions that minimize the seepage through the bottom of the waste disposal sites are discussed in Section E.4.3(b).

For dry ash and dry FGD sludge disposal sites, water that comes in contact with these wastes from rain or melting snow can be minimized by:

i) reducing the exposed area of waste during disposal operations by increasing the height of waste pile for a given waste volume and by developing the site in modules;
ii) reducing the exposed area of waste after disposal by covering the waste pile with a low permeability cover;
iii) contouring the surface of the disposed waste so that precipitation runs off rather than seeps through the waste.

These considerations are of most importance in areas of net precipitation where seepage and runoff from waste piles are significant.

If the projected solid waste disposal area required for the operating life of the station (typically 25 years) is prepared in stages for fractions of this life (for example, one-year intervals), the duration of terrestrial disturbance will be minimized and the potential uses of the land required will be increased. At one FGD disposal site which is being developed, farming is still being carried out on land that will be used for disposal in future. Top soil from the disposal area is set aside and will be used to cover the waste pile so the area can be returned to farming. If this land cannot be used for farming, reclamation of these areas could include re-vegetation in addition to the placement of low permeability soil on the waste.

The long-term physical and chemical stability of wastes is of concern because this will determine the ways in which the land can be re-used and the long-term effects of the wastes on the terrestrial and aquatic environments. For example, reclamation of the disposal site will generally require as a minimum that the waste can support heavy mechanical equipment. FGD sludge fixed by addition of fly ash or fly ash and lime will generally have a physical strength adequate for this (minimum unconfined compressive strength of approximately 200 kPa) (62). For specific re-use applications a greater physical strength may be required. The chemical stability of the waste will determine whether the disposal site can be revegetated, used for cropland etc.

Two FGD waste disposal areas are shown in Figures E.34 and E.35 (63). As illustrated, modular development can be practiced with both wet and dry FGD sludge disposal. The principles of modular development and stacking illustrated also apply to dry ash disposal sites. The wet gypsum stack shown in Figure E.35 is not the preferred method of disposal. It occupies a larger volume and leachate is less controllable than for a dry stacking technique.

Modular development of ash lagoon disposal sites minimizes wastewater production by reducing the area that is under a standing hydraulic head at any one time.

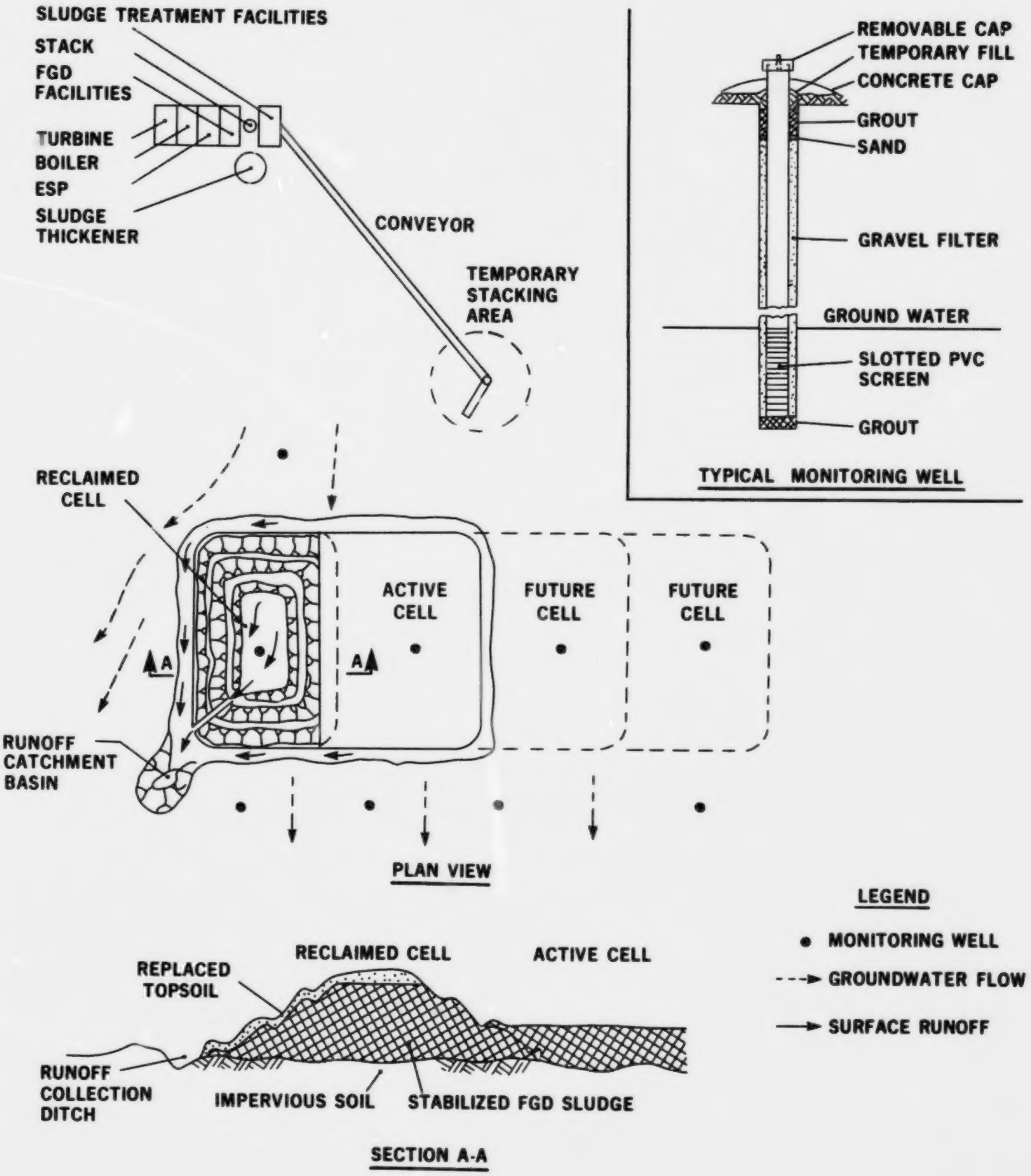
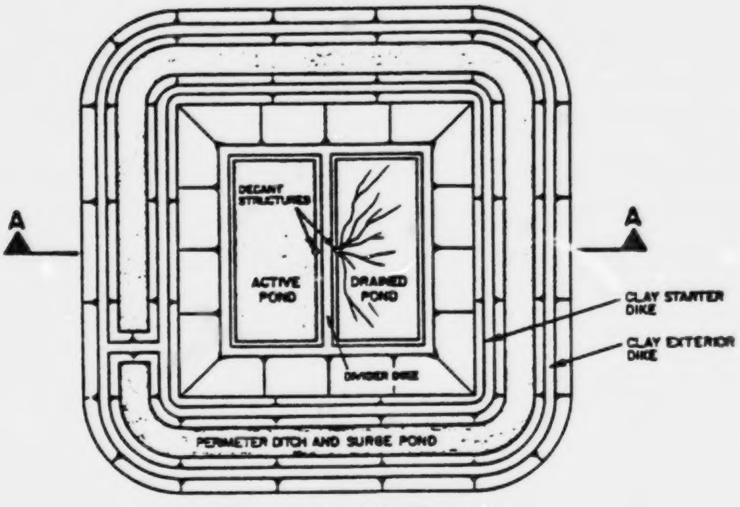
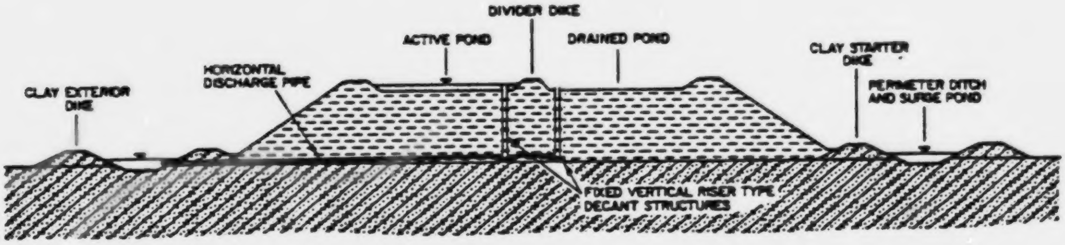

SLUDGE TREATMENT FACILITIES
STACK
FGD FACILITIES
TURBINE
BOILER
ESP
SLUDGE THICKENER
CONVEYOR
TEMPORARY STACKING AREA
REMOVABLE CAP
TEMPORARY FILL
CONCRETE CAP
GROUT
SAND
GRAVEL FILTER
GROUND WATER
SLOTTED PVC SCREEN
GROUT
TYPICAL MONITORING WELL
RECLAIMED CELL
A
A
ACTIVE CELL
FUTURE CELL
FUTURE CELL
RUNOFF CATCHMENT BASIN
PLAN VIEW
LEGEND
● MONITORING WELL
---➤ GROUNDWATER FLOW
⟶ SURFACE RUNOFF
RECLAIMED CELL
ACTIVE CELL
REPLACED TOPSOIL
RUNOFF COLLECTION DITCH
IMPERVIOUS SOIL
STABILIZED FGD SLUDGE
SECTION A-A

FIGURE E.34 DESIGN FOR A TYPICAL FGD SLUDGE LANDFILL SITE (63)


A
A
DECANT STRUCTURES
ACTIVE POND
DRAINED POND
DIVIDER DIKE
CLAY STARTER DIKE
CLAY EXTERIOR DIKE
PERIMETER DITCH AND SURGE POND

GYPSUM STACK SITE PLAN


DIVIDER DIKE
ACTIVE POND
DRAINED POND
HORIZONTAL DISCHARGE PIPE
CLAY EXTERIOR DIKE
CLAY STARTER DIKE
PERIMETER DITCH AND SURGE POND
FIXED VERTICAL RISER TYPE DECANT STRUCTURES

SECTION A-A GYPSUM STACK CROSS SECTION

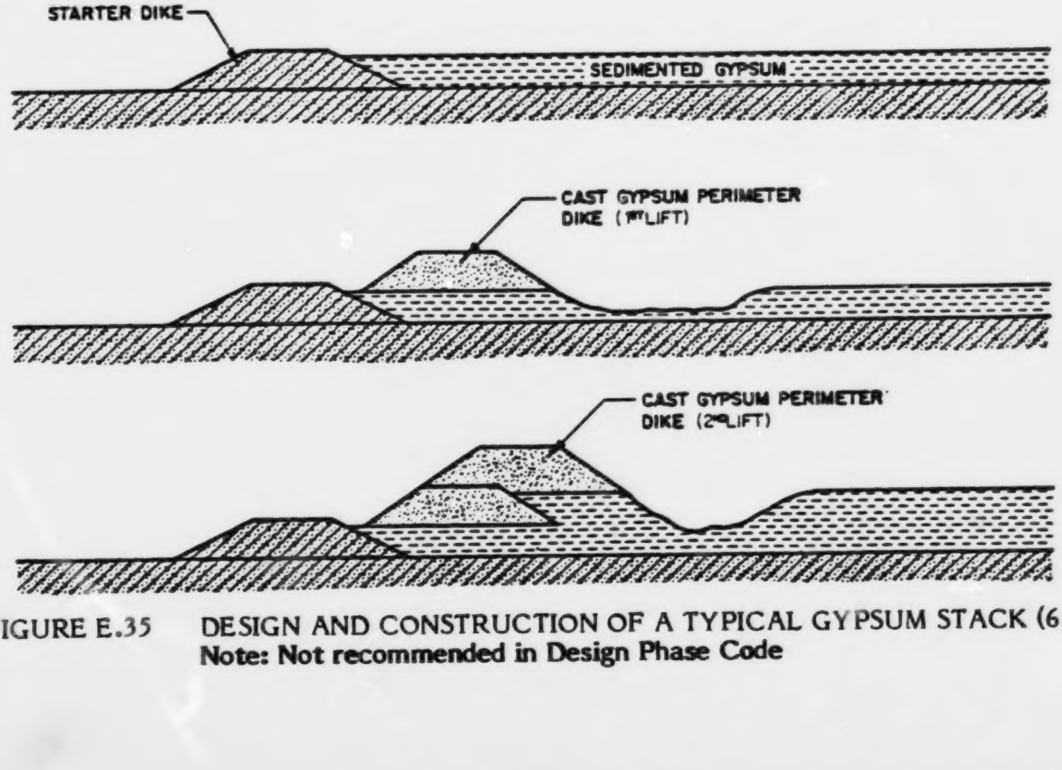

STARTER DIKE
SEDIMENTED GYPSUM
CAST GYPSUM PERIMETER DIKE (1ST LIFT)
CAST GYPSUM PERIMETER DIKE (2ND LIFT)

FIGURE E.35 DESIGN AND CONSTRUCTION OF A TYPICAL GYPSUM STACK (63)
Note: Not recommended in Design Phase Code

Other parts of the disposal area remain available for productive use until needed and each cell can be reclaimed for use after it has been filled. Such a modular lagoon system is being used at the Poplar River G.S. (5).

It is not expected that significant additional costs or operating attention would be required for modular development and disposal area minimization. In fact modular development is currently a common practice in the electric utility industry. Waste disposal sites must be developed in any case, and materials handling equipment such as front end loaders and bulldozers may be continuously available at these sites. In some cases, capital expenditures for developing and lining a disposal area may be reduced or delayed. The advantage of reducing total water lost to evaporation will also be an important factor in arid regions of the country.

Current designs for solid waste storage at sites associated with nuclear stations incorporate covering of medium and low level radioactive wastes in concrete structures. Reclamation of this land after the wastes have been transferred to long-term disposal sites would be considered in the decommissioning of the storage facility.

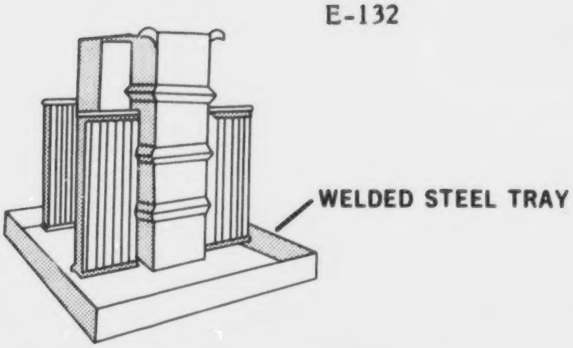
RECOMMENDATION R207. For the disposal of boiler ashes, flue gas desulphurization wastes and station refuse, appropriate design provisions should be made so that:

i) disposal sites are developed in stages during the operating life of the station;
ii) all wastes have physical and chemical stability suitable for land reuse;
iii) all disposal sites are contoured to minimize ingress of precipitation prior to completion;
iv) all disposal sites are reclaimed for beneficial use(s) prior to abandonment.

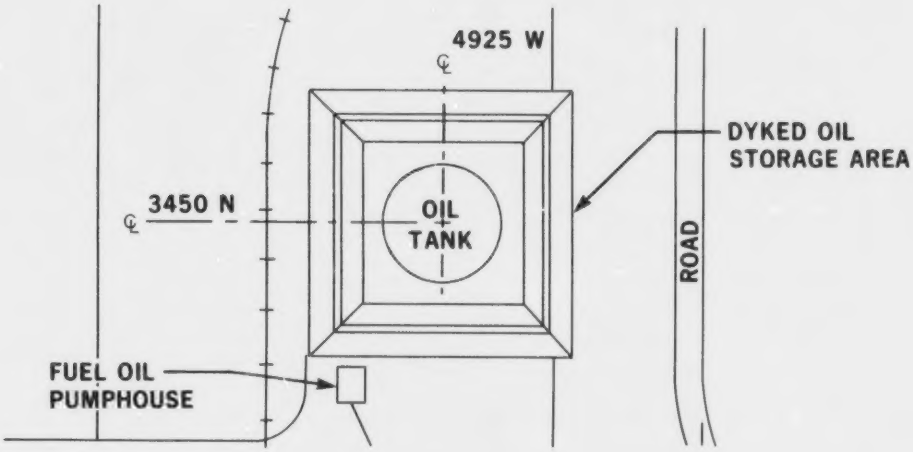
E.4 Wastewater Containment

E.4.1 Containment Practices and Technologies. Containment facilities prevent the uncontrolled release of wastewater, facilitate treatment and/or reuse, and provide temporary or ultimate storage for liquid and solid wastes. Such facilities may be catch basins, sumps, retention ponds, evaporation ponds, lagoons, and enclosed perimeter dikes around fuel storage areas, solid waste disposal areas and other specific features (e.g., switchyards) on the generating station site. Figure E.36 illustrates several typical containment facilities.

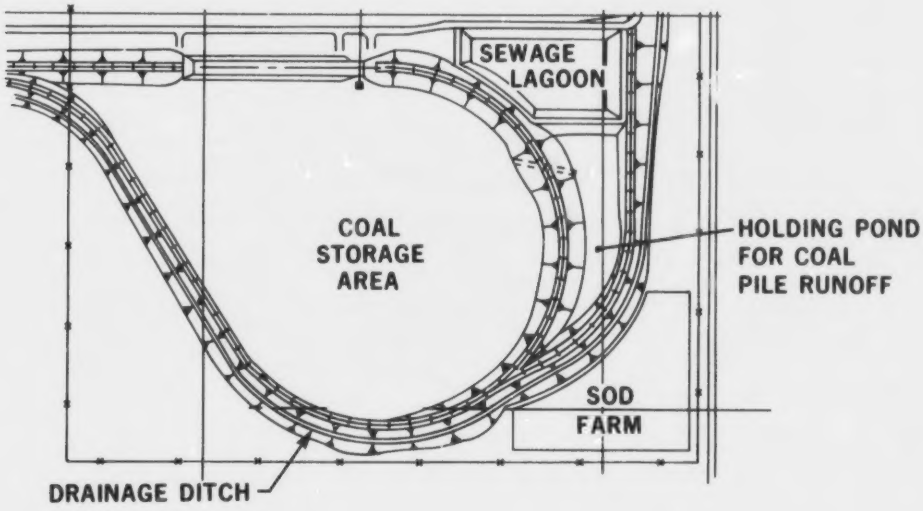
Indoor containment facilities are typically metal or concrete trays, basins, hoppers, tanks or sumps. Containment around specific equipment (e.g., transformers) or for specific areas of the plant may be enclosed metal or concrete perimeter barriers.


WELDED STEEL TRAY

(a) STEEL TRAY FOR TRANSFORMER LEAK CONTAINMENT


4925 W
℄
DYKED OIL
STORAGE AREA
℄ 3450 N
OIL
TANK
ROAD
FUEL OIL
PUMPHOUSE

(b) OIL STORAGE AREA PERIMETER DIKE


SEWAGE
LAGOON
COAL
STORAGE
AREA
HOLDING POND
FOR COAL
PILE RUNOFF
SOD
FARM
DRAINAGE DITCH

(c) HOLDING POND FOR COAL PILE RUNOFF

FIGURE E.36 EXAMPLES OF CONTAINMENT FACILITIES AT STEAM ELECTRIC GENERATING STATIONS (5)

Outdoor containment facilities may also be metal or concrete barriers for smaller areas, such as individual concrete containment basins beneath transformers or for the retention of low volume liquid or solid wastes. However, more commonly, wastewater containment outdoors is provided by earthfill dikes constructed around particular facilities such as fuel oil storage areas, switchyards and ash slurry pipeline routes, or to form retention ponds or lagoons.

Virtually all Type 2 wastewaters at steam electric generating stations should be contained for quality verification prior to release to facilitate treatment if necessary, and to maximize the potential for reuse in other plant processes. In addition, containment should be provided around all equipment, facilities and areas in the station or on the station site where there is a potential for Type 2 wastewaters to be produced from leaks or spills.

Special precautions should be taken in providing containment for potential leaks or spills from bulk chemical storage areas or vessels. Separate storage and diking, or drainage to separate pits, should be provided for chemicals such as acid and caustic which would react violently with one another in an accident involving spills of both. Chemical spills that require special treatment should be routed to holding tanks or lined pits for separate treatment. Certain laboratory wastes may also be particularly hazardous and not amenable to treatment, destruction or disposal in station facilities. To aid in determining whether special containment or storage precautions are needed, the aquatic toxicity, reactivity and health hazards of all chemicals used at the station should be known.

Containment dikes around switchyards are not very common. However, due to the size of switchyard areas, significant quantities of potentially contaminated runoff can be generated and should be contained either by barriers around specific equipment or by perimeter dikes around the yard area that will allow runoff to be contained and its quality verified before release.

Leaks, spills and runoff wastewaters occur periodically. Some operational wastewaters are also generated only periodically such as wastewaters from boiler fireside, boiler waterside, air preheater and stack cleaning. These wastewaters are often highly contaminated and can be produced in significant quantities. Special precautions should be taken to ensure that containment provides adequate flow equilization to facilitate treatment.

RECOMMENDATION R208. Wastewater management system designs should include the following features:

i) containment for all contaminated or potentially contaminated liquid releases (e.g. normal system blowdowns, equipment washdowns and leaks, spills and surface runoff from precipitation, etc.);

ii) separate collection facilities for similar wastewaters (e.g., oily wastes, radioactive wastewaters, boiler cleaning wastes etc.);

iii) separate containments for particularly hazardous substances (e.g., polychlorinated biphenyls, metal cleaning and decontamination wastes, radioactive wastewaters, etc.);

iv) separate containments for bulk chemicals that react violently with each other (e.g., acids and alkalis).

E.4.2 **Indoor Containment Design Capacity.** Indoor containment facilities within the station do not have to account for runoff resulting from precipitation or snowmelt. Hence, the primary considerations are the variablity of process wastewater flows, the capacity of oil and chemical storage vessels and the maximum probable volumes of oil, fluid or other wastewaters that would be released in the event of supply or discharge line leaks or ruptures.

E.4.3 Outdoor Containment Design Capacity

(a) Design Rainfall Event. When solids and liquids are stored, collected, treated or disposed of out-of-doors, precipitation enters the containment, collector or disposal system and may add sufficiently to the volumes of contained solid or liquid to overflow the containment system and allow contaminants to escape. The collector and drainage systems for precipitation and runoff from roof drains and yard areas that are not potentially contaminated should be separated from those facilities that collect, contain or treat contaminated wastewaters. This will eliminate flooding of containment systems by uncontaminated surface runoff. It will also minimize the volumes of wastewaters requiring treatment.

The only way to prevent accumulation of direct precipitation in outdoor wastewater or solid waste containment facilities is to cover the facilities. Since this is not always practical, a design allowance must include containment for the maximum anticipated direct precipitation input as well as the anticipated volumes of the contaminated substances for which the systems are designed.

A graph of rainfall duration in hours vs. percent of the 72-hour (3 days) rainfall depth is shown in Figure E.37. This graph shows that a 6-hour rainfall will account for only about 55% of the rainfall accumulation that can be expected over 3 days. However, at the end of 24 hours, about 75% of the total 3-day amount has fallen.

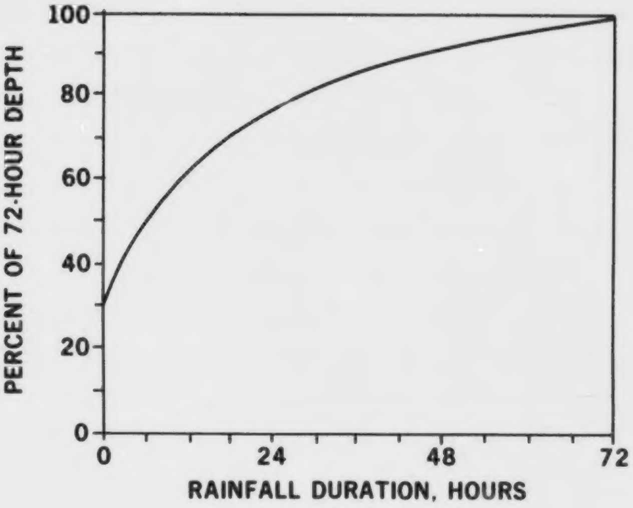
Since the arrangement, location and size of containment facilities may vary considerably from station to station and the design must also take into account the time required for discovery or determination that a flooding condition is approaching, as well as a reasonable time for corrective measures, containment for a minimum of 24 hours of direct input is appropriate. While 24 hours is insufficient to permit accumulation without corrective action over a weekend, for example, it is sufficient to permit standby personnel to realize a problem may be developing and to return to the station to take corrective action. There may be special cases where containments for large coal piles or ash lagoons require containment for precipitation over longer periods.

Since the intent is to prevent overflow, the probability of a maximum precipitation event in the site area over the lifetime of the station must also be considered in the design of retention facilities. A rainfall event of a given duration which has a probability (p) of being equalled or exceeded an average of once in 100 years ($p= 1/100 = .01$) is referred to as a 100-year rainfall event and is said to have a return period of 100 years. The "return period" is the inverse of the probability of the event. Figure E.37 shows a graph of return period, in years, of a 24-hour duration rainfall vs. percent of the 100-year, 24-hour depth. Note that an anticipated 25-year rainfall event provides about 80% of the rainfall of a 100-year storm. Since an average lifetime of a station is often estimated at 30 years, designs based on a once in 25-year maximum would virtually guarantee an overflow one or more times within the average station lifetime. A 100-year, 24-hour design criterion reduces the probability of an overflow during the lifetime of the station to less than 50%. Another common design criterion is to consider one event (say in 10-year, 24-hour event) and apply a safety factor to it (say 1.5). This could result in the same value as a 1 in 100-year, 24-hour event.

RECOMMENDATION R209. Waste liquid collection and containment facilities should be designed to contain the maximum volume of liquid that could reasonably be expected to be in storage prior to any of the following events and:

i) the maximum wastewater that will be generated in any 24-hour period;

ii) the maximum waste volume that will enter the containment in the event of a leak or spill; or



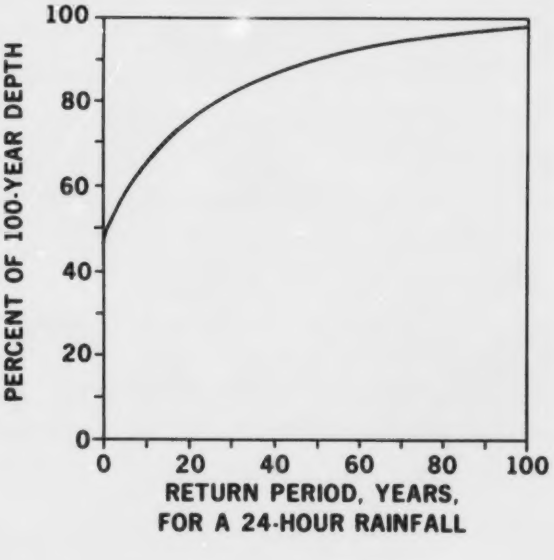


FIGURE E.37 RAINFALL RETURN PERIOD AND DURATION CURVES (84)

iii) the accumulated precipitation of a 100-year return period, 24-hour precipation event for outdoor containments.

(b) Seepage Control Technologies and Design Permeabilities. Seepage from power plant facilities such as ash lagoons, dry ash disposal areas, FGD waste disposal areas, other chemical waste disposal areas, and oil and chemical storage containment areas have the potential to cause environmental damage to groundwater and surface water. It is therefore necessary that such releases be minimized. One way of doing this is to ensure that an appropriate barrier exists between the area of potential seepage and the groundwater or surface water to be protected.

As a first step in this design process, a hydrogeological survey by appropriate experts is required in the area of the proposed disposal or containment facility. The types of soils underlying the facility, their thicknesses and permeabilities, and the extent of fracturing must be determined as accurately and completely as possible. The extent of groundwater movements, the locations of aquifers, and seepage flow nets under the proposed site must be determined.

Several methods (85,86) are available to determine permeability, such as ASTM D2434, falling head tests, test strips using a special dual cylinder infiltrometer device, analysis of the rate of fall of the water table, and the flow net analysis method. The constant elevated pressure method is outlined in a U.S. EPA publication (87). Two methods which could be used for in situ testing are described in a report by John D. Paterson & Asociates Ltd. (88).

Once the hydrogeology underlying the proposed site is understood, decisions can be made regarding the most practicable method of seepage control. Obviously, the least expensive approach would be to use the existing soil in the area of the site as a seepage barrier. If the material is high in clay content it may be impermeable enough, either in its natural state or when compacted, to be used as a liner by itself or in conjunction with other underlying material. For locations where this is not the case, other liner materials may be necessary.

Alternative liners may be classified as admixed liners and synthetic polymeric membranes. Admixed liners are formed in place from a mixture of imported materials. These liners can be divided into hard surface liners and soil sealants. The hard surface liners can be further subdivided into two classes based on asphaltic composition and portland cement composition. The soil sealants can be separated into natural and synthetic materials. Asphaltic hard surface liners, such as asphalt concrete, hydraulic asphalt, concrete, emulsified asphalt on nonwoven fabric, and bituminous seal-catalytically blown asphalt, have permeabilities within the range of 10^{-7} to 10^{-9} cm/s. However, some are susceptible to cracking. The main hard surface liner based on portland cement composition is soil cement. To achieve low permeabilities, fine-grained soils must be used. Acid environments are a major detriment, but permeabilities of 10^{-7} cm/s have been achieved. Soil sealants, as distinct from hard surface liners, are designed to mix with the existing soil. Common forms of this group are bentonite and clay sealants. These materials will swell in the presence of water, creating a seal. The clay mineral montmorillonite is normally responsible for the swelling. The seal afforded by naturally occurring clay and untreated bentonite may be impaired by cation exchange with the wastes being retained. However, treated bentonite such as Saline Seal 100 is cation exchange resistant and permeabilities of 10^{-7} to 10^{-8} cm/s have been reported. Other soil sealants are waste tailings slimes, chemical sealants, and latex sealants. These materials are reportedly not very reliable and permeabilities achieved are generally greater than 10^{-6} cm/s. The chemical liners are susceptible to aging and they, as well as latex sealants, are more costly than other alternatives (89). Synthetic polymeric membrane liners can be separated into plastics and elastomers (synthetic rubbers). The plastic liners are polyvinyl chloride (PVC), polyethylene (PE), chlorinated polyethylene (CPE) and hypalon. Generally, permeabilities of 10^{-9} to 10^{-10} cm/s can be achieved. Special care must be taken during installation to ensure that the individual sheets are seamed correctly and that the liner itself is not ruptured. PVC suffers from aging and deterioration from plasticizer loss due to water extraction or heat volatilization. CPE, on the other hand, has excellent weathering characteristics because no plasticizers are used. Hypalon, a chlorsulphonated polyethylene, exhibits exceptional resistance to aging and weathering since it slowly cures, in use, to an elastomeric material (89). The elastomers describe a group of liners consisting of butyl rubber, ethylene-propylene rubber (diene monomer) also known as EPDM, neoprene and elasticized polyolefins. These can generally achieve permeabilities of 10^{-10} cm/s. Butyl rubber's resistance to aging and weathering is good but EPDM's is reportedly slightly better. Neoprene's resistance to aging with respect to sunlight exposure is reportedly poor.

Many U.S. states have adopted regulations requiring hazardous waste landfills and surface impoundments to have clay liners with permeabilities not greater than 1×10^{-7} cm/s (90). The U.S. EPA in 1978, proposed regulations for the disposal of hazardous waste which would result in landfills and surface impoundments being lined with material having a permeability not greater than 1×10^{-7} cm/s, and at least 1 m thick (91).

Several sources (92-96) indicate that clay deposits having permeability of the order of 1 x 10^{-7} cm/s exist across North America. Figure E.38 shows the coefficient of permeability of materials as affected by the degree of compaction (85). As a result of the Key Lake Board of Inquiry (97,98) a 1-metre thick seal of compacted till and bentonite with a permeability of not greater than 1 x 10^{-7} cm/s will be constructed under the entire uranium tailings storage area (approximately 0.4 km^2) at Key Lake in northern Saskatchewan.

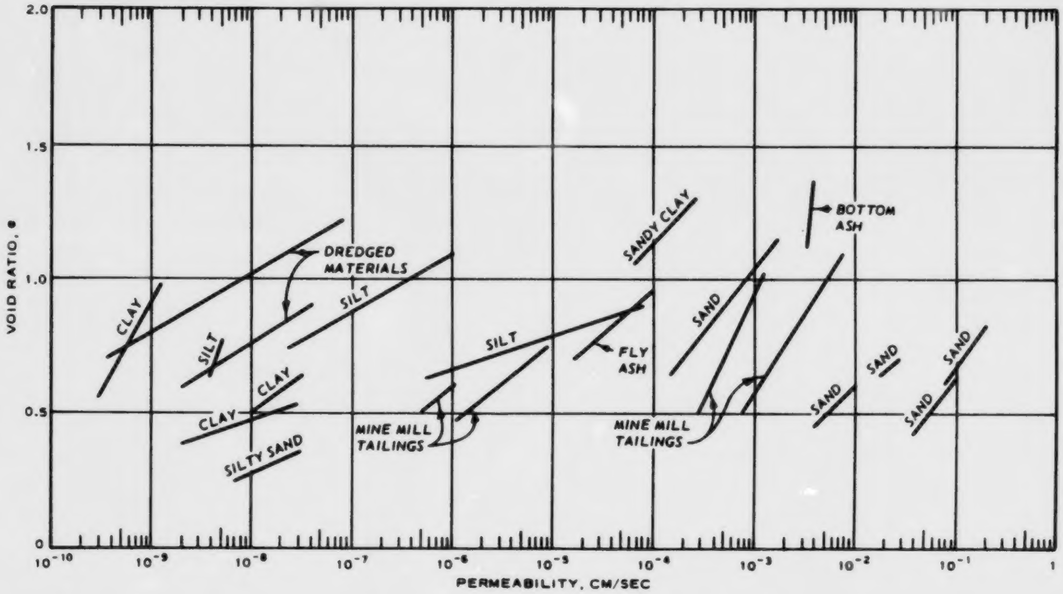


FIGURE E.38 COEFFICIENT OF PERMEABILITY OF MATERIALS AS AFFECTED BY DEGREE OF COMPACTION (85)

The concept of an equivalent material thickness and permeability is useful for describing the degree of seepage control achieved. This concept provides maximum flexibility to the designers and constructors of the containment site. For example, the same seepage rate could result from a lesser thickness of a less permeable material, or a greater thickness of a more permeable material.

Equivalent permeability can be calculated using the following equation:

$$P_{equiv} = \frac{T_{equiv}}{\sum_i \frac{T_i}{P_i}}$$

where: P_{equiv} = equivalent permeability (cm/s)
T_{equiv} = equivalent thickness (m)
P_i = permeability of layer i (cm/s)
T_i = thickness of layer i (m)

One western Canadian utility was able to achieve the overall equivalent of a 1-metre thickness of 1.6×10^{-8} cm/s at its ash lagoon. This was accomplished with three layers, the first being 0.3 m of 1×10^{-8} cm/s compacted oxidized till which was imported. This overlaid the second layer of 8.8 m of 6×10^{-5} cm/s undisturbed oxidized till which, in turn, overlaid the third layer of 6.4 m of 2×10^{-7} cm/s unoxidized till. The second and third layers were indigenous to the site.

In the case of ash or FGD lagoons generally, their large size raises some question as to how practicable it would be to achieve the equivalent of 1 metre of 10^{-7} cm/s permeability throughout the country. The equivalent of a 1-metre thickness not greater than 5×10^{-7} cm/s permeability is considered more realistic for ash lagoons.

For high sulphur (>1% sulphur content) coal pile seepage and runoff containment, the equivalent of a 1-metre thickness of not greater than 1×10^{-7} cm/s permeablity would be more appropriate considering the coal pile's smaller size and the possibly more hazardous nature of its runoff and seepage compared to an ash lagoon.

In contrast, for low sulphur (<1% sulphur content) coal pile seepage and runoff containment, the equivalent of a 1-metre thickness of not greater than 1×10^{-6} cm/s permeability would be appropriate because of the less hazardous nature of the runoff and seepage. This permeability criterion would also be appropriate for dry or dewatered ash and FGD waste disposal sites because the absence of a standing head of water would mean less seepage than from an ash or FGD lagoon.

The requirements are somewhat different for containment areas around fuel or chemical storage facilities. These areas are only required to contain spilled or leaked fuel or chemicals or rainwater contaminated with them until such time as they can be pumped out for treatment or disposal. Environment Canada's draft guidelines entitled "Recommended Practice Respecting Petroleum Storage Facilities and Containment Dykes" recommended the use of a material having a permeability of not greater than 1×10^{-5} cm/s for the containment of leaked or spilled petroleum products. The equivalent of a 1-metre thickness of not greater than 1×10^{-5} cm/s permeability is also considered appropriate for steam electric plants.

Generally, the installation of liners is labour intensive. The installation of flexible membrane liners in particular requires careful preparation of the subgrade to ensure the soil surface is sufficiently smooth and compacted and free of large or sharp rocks which may damage an overlaid membrane liner. In addition, some liners require an overlaid protective soil cover as protection against the effects of sun and wind exposure and mechanical damage during the operation of the site. This cover usually consists of clean permeable soil and may be up to 0.5 m or more in thickness. It may also be used as an underdrainage system for leachate collection.

A leachate collection system generally consists of strategically placed perforated drain rock, bottom ash or perforated pipes surrounded by drain rock (see Figure E.39). The pipe can be installed in a trench below liner grade or on top of the liner. The system can be installed either around the perimeter of the area or in the form of a complex network of collection pipes (see Figure E.40). The latter is used where the areas involved are very large and/or the allowable head buildup is small. The collection system is drained to a sump or a series of sumps from which the leachate is withdrawn. The bottom of the site is usually sloped a minimum of 1 percent down to the collection pipes and the collection pipes themselves are sloped to the sumps.

A leachate collection system may be considered as an alternative means of reducing the total rate of seepage. In this case the thickness and permeability of the seepage control barrier could be reduced or increased respectively in proportion to the reduction in head achieved by the leachate collection system. The effect of such a measure on the overall seepage rate can be seen in the following equation:

$$Q = kHA/T$$

where: Q = seepage rate (m^3s)
k = permeability (m/s)
H = hydraulic head above the seepage control barrier (m)
T = thickness of the seepage control barrier (m)
A = area over which seepage occurred

Concrete containment structures and underdrainage collection and detection systems are used in recent radioactive low and medium level waste storage sites. In addition, the area between containment structures could have an equivalent permeability of 1-metre of less than 1×10^{-7} cm/s material. For example, tarmac could be used to ensure virtually no seepage from any area of the relatively small site.

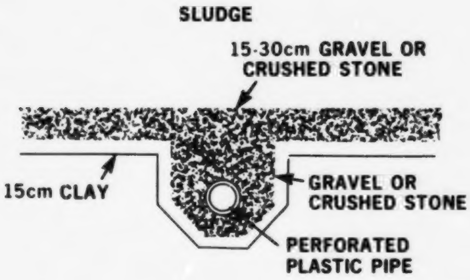

SLUDGE
15-30cm GRAVEL OR CRUSHED STONE
15cm CLAY
GRAVEL OR CRUSHED STONE
PERFORATED PLASTIC PIPE

FIGURE E.39 UNDERDRAIN FOR LEACHATE COLLECTION (99)

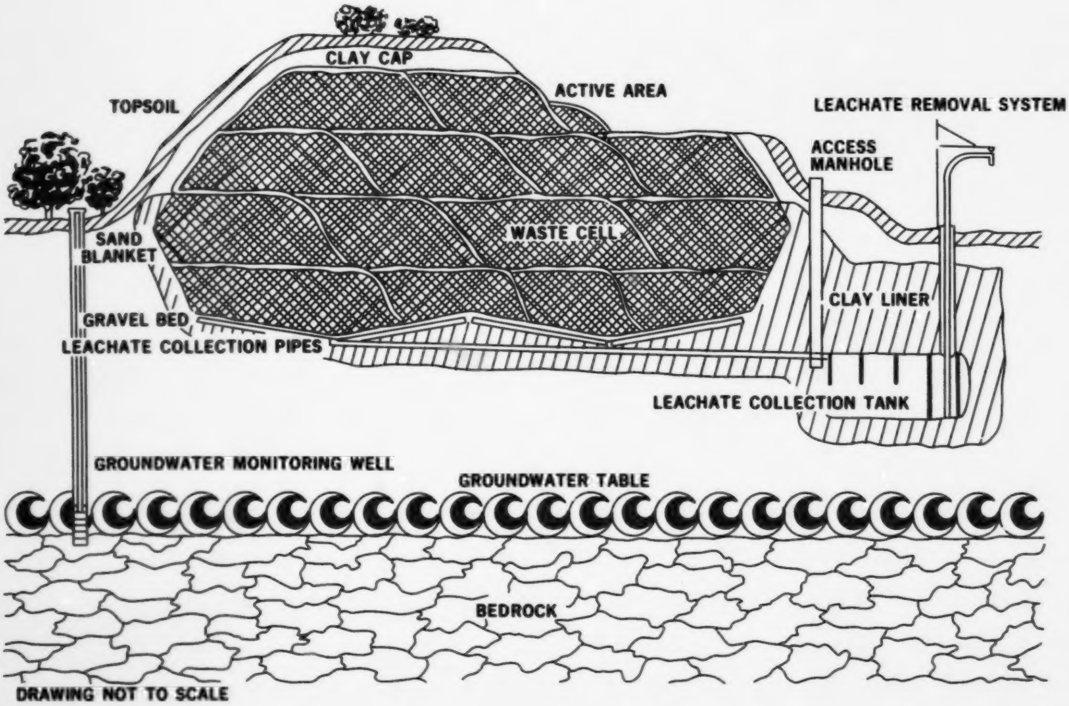

CLAY CAP
ACTIVE AREA
TOPSOIL
LEACHATE REMOVAL SYSTEM
ACCESS MANHOLE
WASTE CELL
SAND BLANKET
CLAY LINER
GRAVEL BED
LEACHATE COLLECTION PIPES
LEACHATE COLLECTION TANK
GROUNDWATER MONITORING WELL
GROUNDWATER TABLE
BEDROCK
DRAWING NOT TO SCALE

FIGURE E.40 LEACHATE COLLECTION SYSTEM (100)

When the operating life of a waste disposal area (landfill or lagoon) has ended, proper closure procedures must be implemented to ensure its environmental impact is minimized throughout the years that follow. If the wastes are to remain in place, they should be dewatered and the entire disposal area should be sealed with a clay cap to minimize water seepage into the area and wind erosion of the surface wastes. This should be overlaid with soil capable of supporting indigenous vegetation of which the top portion should be topsoil. Vegetation should be planted to minimize erosion. In addition groundwater monitoring should be maintained to detect any seepage which may occur.

Ash lagoon seepage control poses a problem because of the very large areas involved (up to 3 km^2 or more). From Figure E.41 it can be seen that the seepage rate calculated from a 2 000 000 m^2 (2 km^2) area, based on a 5-m head and with a barrier of 1 m thickness of material having a permeablity of 5×10^{-7} cm/s, would be 50 L/s (1 600 000 m^3/a). Any permeabilities higher than 5×10^{-7} cm/s would result in very large seepage volumes given the size of the disposal areas often used. Developing the lagoon area in cells as described in Section E.3.4 will help to reduce concern regarding surface water and groundwater contamination from high seepage rates.

In summary, seepage from waste disposal and fuel or chemical storage areas is a potential environmental problem and should be controlled. A number of liner materials and design and construction methods exist to reduce seepage from containment areas. Constructing ash lagoons in cells can be an effective seepage control method.

RECOMMENDATION R210. Seepage to groundwater or surface water should be controlled by a naturally occurring and/or constructed barrier which meets the following minimum conditions with respect to material thickness and maximum water permeability, measured over the entire depth from the bottom of the containment area to the aquifier.

i) The equivalent of 1 m of 10^{-7} cm/s material for:
  - ***a) the base of high sulphur coal piles (i.e. coal>1% sulphur (S) content),***
  - ***b) high sulphur (>1% S) coal pile runoff containment facilities,***
  - ***c) chemical waste storage and treatment lagoons (except as noted below),***
  - ***d) the area surrounding solid radioactive waste storage cells.***

ii) The equivalent of 1 m of 5×10^{-7} cm/s material for:
  - ***a) ash lagoons,***
  - ***b) flue gas desulphurization waste lagoons.***

iii) The equivalent of 1 m of 1×10^{-6} cm/s material for:
  - ***a) the base of low sulphur (<1% S) coal piles,***
  - ***b) low sulphur*** **(<1% S) coal pile runoff containment facilities,**

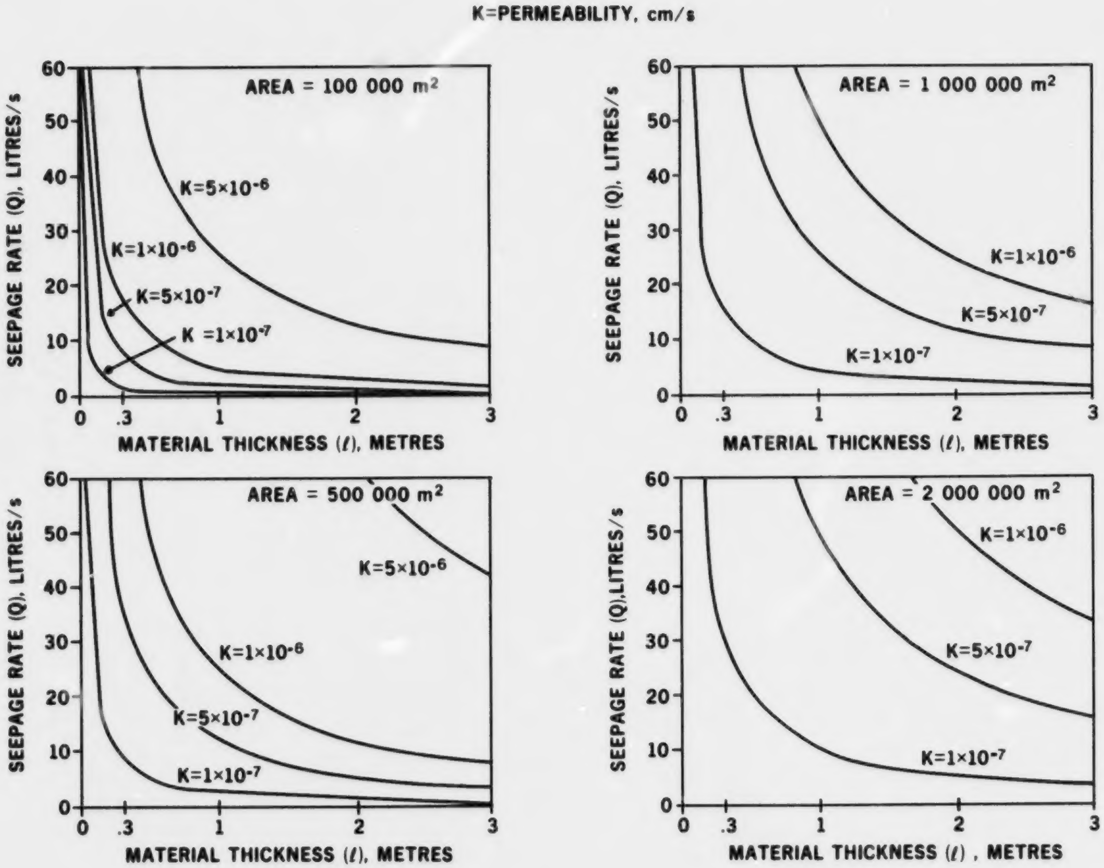


FIGURE E.41 SEEPAGE RATES BASED ON A 5-METRE HEAD

   - c) ***dry or dewatered ash disposal sites,****
   - d) ***dry or dewatered flue gas desulphurization waste disposal sites.***

iv) ***The equivalent of 1 m of 1 x*** 10^{-5} ***cm/s material for:***

   - a) ***oil tank farm containment facilities,***
   - b) ***transformer and switchgear containment facilities,***
   - c) ***chemical storage containment facilities,***
   - d) ***all other diversion and collection facilities.***

---

* ***Seepage control recommendations for coal mine disposal of ashes are deferred. "Ash" includes combustion wastes from conventional boilers, fluidized bed combustors, and other combustion devices.***

E.5 Wastewater Treatment

E.5.1 General. In Section E.5.2 wastewater treatment processes are described and selected design and performance data relevant to the power generation industry are given. For a better understanding of any of the processes, several textbooks provide excellent general information concerning definitions and descriptions of unit processes in industrial water pollution control (101, 102), basic principles of preliminary treatment, primary sedimentation and biological treatment (103), specific treatment technologies for selected parameters (As, B, Cu, TDS, oil and grease) (104), the chemistry of treatment technologies (105) and basic design data for unit wastewater treatment processes (23, 106).

The application of one or more of the unit processes to specific wastewaters from the power generation industry is discussed in Section E.5.3.

Section E.5.4 provides examples of overall wastewater treatment systems and their integration into a power generation facility.

E.5.2 Wastewater Treatment Processes

(a) Equalization. Many power plant waste streams exhibit large variations in flow and chemical characteristics. Equalization involves the retention of these wastewaters in holding facilities and their release in such a manner that variations in flow and chemical characteristics are reduced or minimized. Increasing the degree of equalization of wastewaters decreases the peak design flow rate and thereby reduces the size, and hence cost, of treatment equipment and the range of chemical feed rates. Equalization may also improve wastewater treatment system performance (107). The design of equalization facilities depends on site-specific factors such as the variability in flow characteristics of the wastewaters and nature of the treatment process. One design methodology involves calculating the required detention time for an equalization facility by the equation:

$$t = \frac{\Delta t \cdot Si}{2 \cdot Se} \qquad (108)$$

where: t = equalization facility detention time (h)

Δt = time of collection of each inflow composite sample (h)

Si = variance of influent waste parameter

Se = acceptable variance of effluent parameter

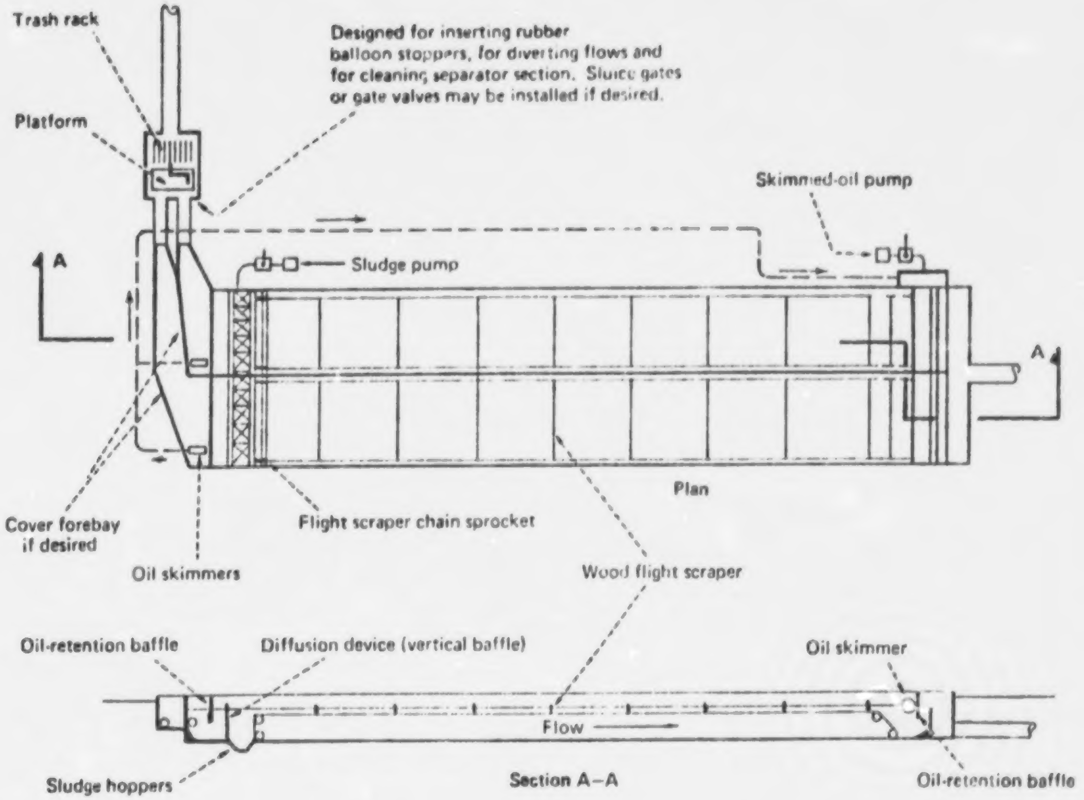
(b) Preliminary Treatment. Floating and coarse suspended material, such as sticks, rags, etc., are screened and removed from the treatment plant influent to prevent clogging of down stream processes. Typical screening facilities include bar screens (a series of bars) or fixed or travelling screens (wire meshing) that have opening sizes of 5 mm or greater. Screens may be placed in trenches near sumps to protect sump pumps.

Heavy granular matter, such as sand is allowed to settle in a small settling tank called a grit chamber. Removal of the grit protects pumps and other treatment facilities that will handle the wastewater. In one example of a grit chamber designed for the power generating industry, a retention time of 10 minutes was provided in a 6.1 m x 18.3 m grit chamber (109). At flows of 925 m^3/d (average) and 1 980 m^3/d (maximum), linear velocities attained were 0.74 m/min and 1.86 m/min, respectively.

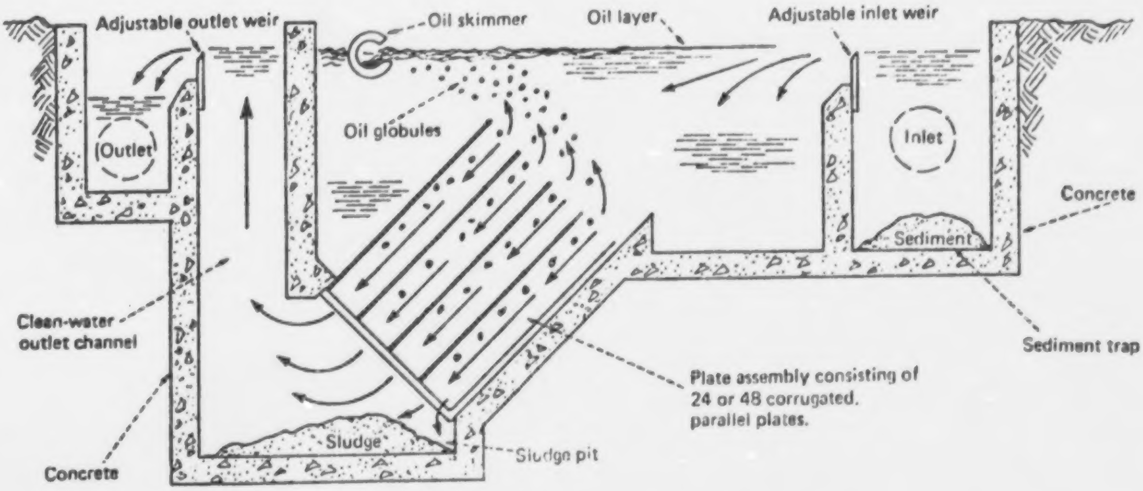
Typical screening and grit chamber facilities have also been described in the textbooks referenced in Section E.5.1.

(c) Oil Removal. Oil may be removed from wastewaters in a non-turbulent basin in which free oil, with a specific gravity less than that of water, rises to the surface. The oil may be removed from the surface by floating oil booms and skimmers or mechanically driven rakes. Common types of oil removal equipment, the American Petroleum Institute (API) separator and the corrugated plate interceptor (CPI), are shown in Figure E.42 (110).

Colloidal or emulsified oil not readily separated by gravity can be removed by air flotation. In this process air bubbles released in the wastewater form on the surface of suspended or oily materials or are attached to the particles by surface energies. The aggregate which is formed has an average density less than that of water and rises to the surface where it can be skimmed. Performance data for a typical air flotation unit is shown in Figure E.43 (110).

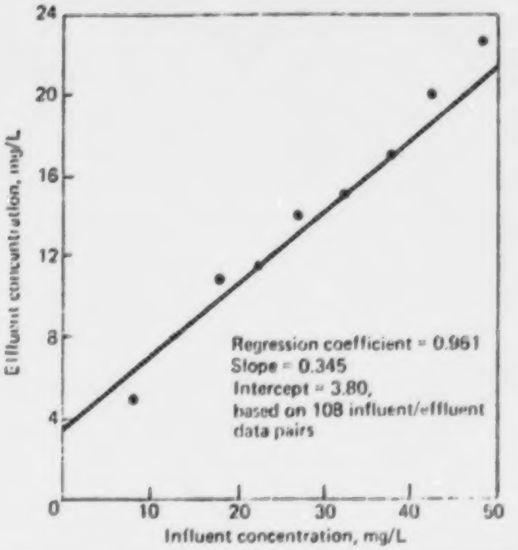

Trash rack
Designed for inserting rubber balloon stoppers, for diverting flows and for cleaning separator section. Sluice gates or gate valves may be installed if desired.
Platform
Skimmed-oil pump
A
Sludge pump
A
Plan
Cover forebay if desired
Flight scraper chain sprocket
Oil skimmers
Wood flight scraper
Oil-retention baffle
Diffusion device (vertical baffle)
Oil skimmer
Flow
Sludge hoppers
Section A–A
Oil-retention baffle

API Oil-Water Separator

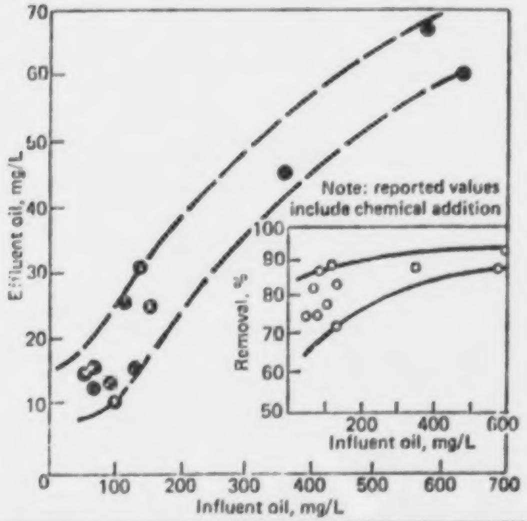

Adjustable outlet weir
Oil skimmer
Oil layer
Adjustable inlet weir
Oil globules
Outlet
Inlet
Concrete
Sediment
Sediment trap
Clean-water outlet channel
Plate assembly consisting of 24 or 48 corrugated, parallel plates.
Sludge
Sludge pit
Concrete

Corrugated-Plate Interceptor or CPI Separator

FIGURE E.42 API AND CORRUGATED-PLATE INTERCEPTOR (CPI) OIL/WATER SEPARATORS (110)



Dissolved-air-flotation performance on
oil and gas production wastewaters



DAF-oil-removal performance as a function
of influent concentration for refineries

FIGURE E.43 DISSOLVED AIR FLOTATION (DAF) UNIT PERFORMANCE DATA (110)

(d) Neutralization and Precipitation. The adjustment of the pH of wastewater by addition of an acidic or alkaline chemical or mixing with another waste stream may be required prior to further treatment. Neutralization to approximately pH 6 to 8 will reduce (or eliminate) the corrosive nature of an acidic or alkaline wastewater. Also pH adjustment may promote the removal of certain pollutants. An example is the precipitation of metal hydroxides ($Cu(OH)_2$, $Zn(OH)_2$, $Cd(OH)_2$, $Ni(OH_2)$) from metal laden acidic wastewaters by adjustment of the pH to 9.0 or greater.

Metals precipitate at various pH levels depending on such factors as the metal itself, the insoluble salt that is formed (e.g. hydroxide, carbonate, sulphide, etc.), presence of complexing agents such as ammonia, citric acid, ethylenediaminetetracetic acid (EDTA), etc. Theoretical precipitation curves for various metals as hydroxides are shown in Figure E.44 (111).

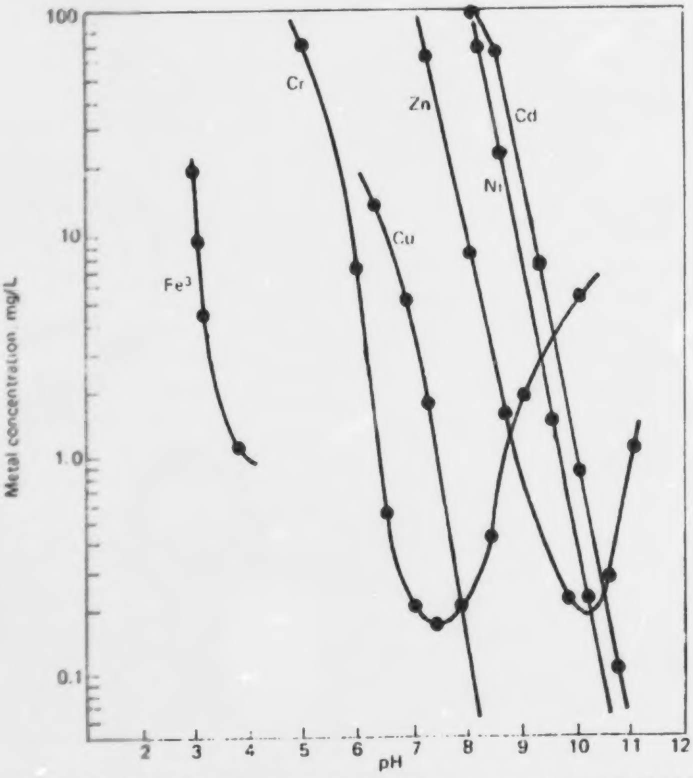


FIGURE E.44 PRECIPITATION OF METALS AS HYDROXIDES (111)

Some applications of the neutralization and precipitation processes to the power generating industry are shown in Table E.43. The effluent quality data shown in

TABLE E.43 SOME EXAMPLES OF NEUTRALIZATION/PRECIPITATION PRACTICES AND PERFORMANCE IN THE POWER GENERATING INDUSTRY

Ref.	Type	Tank Specifications	Flow (m^3/d)	Retention Time	Chemical	Final pH	Parameter	Influent Quality (mg/L)	Effluent Quality (mg/L)
112	N	Rapid mix tank	19 000		NaOH	Neutral	(TSS)		14.6
	N	Rapid mix tank	4 320		NaOH	Neutral	(TSS)		22.2
	N	2 settling basins	25 900	79 h	NaOH	Neutral	(TSS)		6.9
113	P	Tank (34 m^3)	330 000	15 min	Lime	9.0	(TSS)	30-4200	15-20
	N	Tank (15 m^3)	43 000	5 min	50% NaOH or 93% H_2SO_4	6.5-8.5	(oil and grease)	70	<5
	N	Tank (6.7 m (d) 11.0 m (ht))	300	1-2 h	50% NaOH or 93% H_2SO_4	6.5-8.5			
114	P		3 800		NaOH or H_2SO_4	7.1	(SS)		6
							(oil and grease)		3
							(Cu)	5-10	0.07
							(Fe)	1000-2000	0.7
							(Ni)	30-60	0.03
							(Zn)	2-5	2.5
115	P			30 min	Lime (25-50 mg/L)	7.4-8.3	(SS)	40-210	4-16
							(Fe)	1.1-4.5	0.05-0.5
							(Al)	1.8-3.4	0.3-1.7
116	N	Tank (23 m^3)	1 100 -1 600	23-24 min	Lime	7.0			
117	P	-		-	Lime	9-12	(AS)		0.05
							(Cd)		0.05
							(Cu)		0.03
							(Cr(III))		0.05
							(Mn)		1.0
							(Ni)		0.05
							(Pb)		0.10
							(Zn)		0.15
116	N		2 450		H_2SO_4	7.9-8.3	(TSS)		10-20

Table E.43 are dependent on the effect of an additional unit process, that of clarification, which is described in Section E.5.2(f).

(e) Coagulation and Flocculation. Colloidal size particles in wastewater have a high surface charge to mass ratio and consequently the net force between particles is repulsion. This inhibits the coalescing of particles to a size which can readily be separated from the water. Coagulation refers to the destabilization of colloidal suspensions and is often described as including the initial aggregation of the colloidal and finely divided suspended material by chemical assistance. Coagulants are typically inorganic compounds such as alum, lime and ferric chloride which provide cations that will precipitate as the metal hydroxide and generate coagulation. Organic polyelectrolytes can also be used as coagulants.

Flocculation refers to the aggregation of the destabilized particles, or particle agglomeration. Flocculation includes the formation of microflocs, continuing to macroflocs or dense rapidly settling material. Typical flocculants are natural or synthetic organic polyelectrolytes. The mechanisms involved in coagulation are shown in Figure E.45 (106).

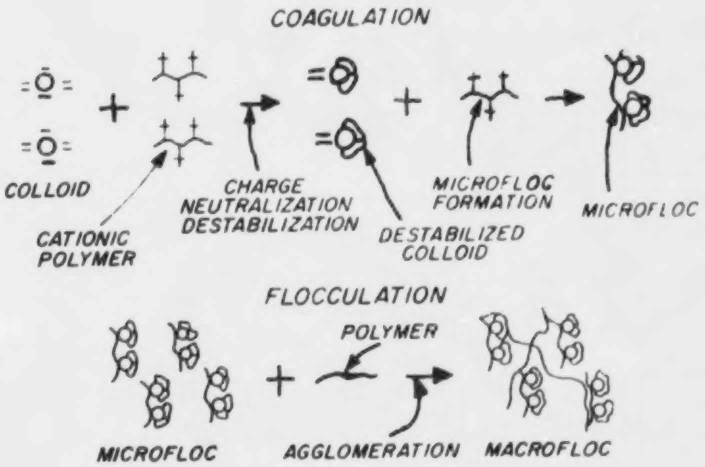

COAGULATION
COLLOID
CATIONIC POLYMER
CHARGE NEUTRALIZATION DESTABILIZATION
DESTABILIZED COLLOID
MICROFLOC FORMATION
MICROFLOC
FLOCCULATION
POLYMER
MICROFLOC
AGGLOMERATION
MACROFLOC

FIGURE E.45 COAGULATION AND FLOCCULATION MECHANISMS (106)

Important parameters in coagulation and flocculation are the choice of chemical and dosage, and the energy input during the rapid mix and flocculation stages.

Optimum levels of energy input exist at which there is a balance between ensuring mixing and particle collision, and avoiding floc shear (106).

Some examples of coagulation/flocculation practices in the power generation industry are shown in Table E.44.

(f) Clarification. During clarification (sedimentation), the fraction of suspended matter with a specific gravity greater than water is removed form the wastewater stream by settling to the bottom of a basin. The settled material can be removed from the basin and is known as sludge.

Sedimentation can be accomplished in lagoons or settling ponds. Since the design of these units may be based primarily on the need to store accumulated settled sludge, their size may be far in excess of that required for sedimentation itself.

Solids removal can also be accomplished in specially designed units called clarifiers and is defined as clarification. Clarifiers are generally sized based on the wastewater flow to the unit and the settling rate of the suspended matter in the wastewater. The critical operating parameter is the loading rate (m^3 of wastewater flow per day per m^2 surface area) or upflow rate, which must be less than the solids settling rate. Individual clarifier designs differ in methods of reducing turbulence and short circuiting. Solids removal from the clarifier must be maintained and is usually accomplished by means of scrapers or rakes on the clarifier bottom which direct the sludge to pumping facilities. A typical clarifier is shown in Figure E.46. Some examples of clarifier specifications and performance from the power generation industry are shown in Table E.45.

(g) Filtration. Filtration removes suspended matter from a carrier liquid by passing the liquid through a porous material. Filtration generally follows sedimentation/clarification and is used to remove fine particulate material.

Filtration operations may be generally classified according to the filter medium. Only granular media filtration, the most common type, is discussed here. Various media, such as sand, gravel, anthracite, etc., have been used alone or in various combinations. A dual-media bed of anthracite and sand, with the larger anthracite particles upstream of the sand has been most commonly used in industrial applications. Bed depth typically varies from 0.6 to 2.4 metres, filters may work under gravity or be pressurized (typically 1 030 kPa), and the direction of flow may be vertical or horizontal (20, 120). Some examples of filter design and performance from the power generation industry are given in Table E.46.

TABLE E.44 SOME EXAMPLES OF COAGULATION/FLOCCULATION PRACTICES IN THE POWER GENERATING INDUSTRY

Ref.	Coagulant	Dosage (mg/L)	Rapid Mix Conditions	Flocculant	Dosage (mg/L)	Flocculation Conditions	Comments
113	$Fe_2(SO_4)_3$ & Lime	-	See note a)	Polymer (Calgon WT-2700)	2.0	Reactor Clarifier Flocct = 20 min & Loading = $m^3/m^2 \cdot d$	b)
115	Alum or $Fe_2(SO_4)_3$	12-50	-	Anionic Polymer	0.5-1.0	-	c)
118	$FeCl_3$	25-90	-	Cationic Polymer	0.2	-	-
119	-	-	-	High density Anionic Polymer	3	-	
109	Alum	5.24	-	Cationic Polymer	2-3	Flash Mix	-

Notes: a) Rapid mixing of $FESO_4$ and combining of lime occurs in neutralization tank prior to reactor clarifier.
b) Flocculation occurs in reactor clarifier.
c) Results of bench scale tests.

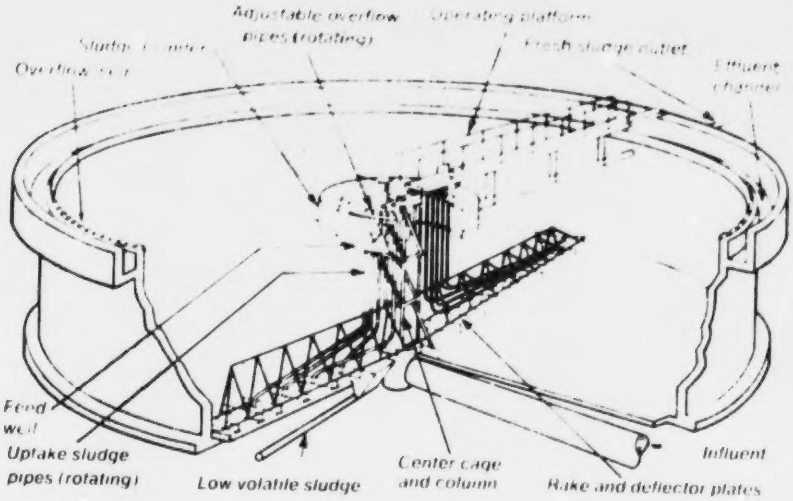

Adjustable overflow pipes (rotating)
Operating platform
Sludge
Fresh sludge outlet
Overflow weir
Effluent channel
Feed well
Uptake sludge pipes (rotating)
Low volatile sludge
Center cage and column
Influent
Rake and deflector plates

FIGURE E.46 TYPICAL CLARIFIER DESIGN (20)

(h) Membrane Processes. These unit processes apply the principle of concentrating pollutants in a fraction of the wastewater (brine) while generating the remainder of the waste stream as "pure" water. Reverse osmosis (RO) and ultrafiltration (UF), two membrane processes, are based on applying pressure to force water through a semipermeable membrane (usually cellulose acetate or a polyamide) that restricts the passage of molecular-sized particles.

In the UF process, separation is based primarily on the size of the solute molecules which, depending upon the particular membrane porosity, can range from about 2 to 10 000 nanometres. In the RO process, the size of the solute molecule is not the sole basis for the degree of removal, although 0.04 to 600 nanometres is generally considered the useful range. In RO, the valency of ionic species is important, and the membrane's ability to reject increases with increasing valency. Thus calcium and magnesium are rejected to a greater extent than sodium; also sulphate is rejected more than chloride. The basis of rejection is more complicated than a simple molecular sieve, but the exact mechanism is still in dispute (121). RO units usually operate at pressures from 2100 to 5500 kPa (300 to 800 psia) to obtain reasonable flow rates (50). By contrast, UF systems usually require only about 175 to 800 kPa (10 to 100 psig) pressure (121).

Two performance parameters by which reverse osmosis membranes are commonly judged are the rate of water flux through the membrane ($m^3/m^2 \cdot d$) and salt

TABLE E.45 CLARIFICATION PRACTICES IN THE POWER GENERATION INDUSTRY

Ref.	Clarifier Specifications	Loading Rate $(m^3/m^2 \cdot d)$	Efficiency	Notes
122	Conventional Circular Clarifier (20 m dia)	18		a
	Conventional Clarifier	35-100		b
112	Settling Basin ($3400 m^3$)	8.15	Ave. Eff. SS=14.6 mg/L	
112	Inclined Plate (Equiv. 15.5 m dia clarifier)	33.4	Ave. Eff. SS=22.2 mg/L	
112	Inclined Plate (Equiv. 12.8 m dia clarifier	33.4	Ave. Eff. SS=7.9 mg/L	
112	Pond ($8500 m^3$)	0.90	Ave. Eff. SS=6.9 mg/L	
112	Pond ($26000 m^3$)	0.65	Ave. Eff. SS=10.3 mg/L	
112	Pond ($185000 m^3$)	0.10	Ave. Eff. SS=8.5 mg/L	
113	Clarifier/thickener (dia.=11.6 m & clarifier zone surface area = $76 m^2$)	45	Eff. SS=15-20 mg/L Eff. oil & grease <5 mg/L (97% SS & Fe removal)	
114	High rate tube settlers	147	Ave. Eff. SS = 6 mg/L Ave. Eff. O&G = 3 mg/L	
58	Pond ($62000 m^3$)	10800^c		d
115	Upflow clarifier (dia. = 11 m)	58.7	Eff. Levels (mg/L) — Removal (%) SS: 4-16 — 90-92 Fe: 0.05-0.5 — 87-95 Al: 0.3-1.7 — 45-91	
115	Ash pond ($150-190000 m^3$)		Eff. Levels (mg/L) — Removal (%) SS: 8-14 — 98-99 Fe: 03-0.4 — 97-99 Al: 0.7-0.8 — ≈100 B: ≈5 — -266	e
122	Clarifier (IPS, 23 m dia)		TSS: 95% removal	
109	Helical Flow Clarifier dia. = 11 m depth = 7.3 m Surface area = $46.5 m^2$)	36 (Ave) 59 (Max)	Eff. SS = 2.7 mg/L (99.7% removal) Eff. Fe = 0.08 mg/L (90% removal)	
123	Tube Settlers (effective surface area = $68 m^2$ tube dia = 2.5 cm tube length = 61 cm)	95	Eff. SS = 13 mg/L (99.7% removal)	

Notes:
- a Applied to limestone slurry wet scrubbing.
- b Applications in the iron and steel industry used as reference examples.
- c Flow (m^3/d); not loading rate.
- d Fly ash disposal pond.
- e Boron leached from ash and so higher effluent levels than influent.

TABLE E.46 SOME EXAMPLES OF FILTER DESIGN AND PERFORMANCE FROM THE POWER GENERATION INDUSTRY

Ref.	Filter Type	Specifications (material, size, etc)	Influent	Effluent Quality
120	Shallow Bed	Bed depth = 0.61-0.91 m anthracite: 0.46-0.61 m sand: 0.30-0.46 m Dia. = 12.2 m (max) Flow rate = 40 900 m^3d	<100 mg/L TSS	5-20 mg/L TSS
20	Shallow Bed	Sand, gravel, anthracite Loading rate = 120 - 230 $m^3/m^2{\cdot}d$	100 mg/L TSS	
124	Shallow Bed	Loading rate = 120 $m^3/m^2{\cdot}d$ Bed depth = 0.9/m	<100 mg/L TSS	<1 mg/L Fe <1 mg/L Cu <15 mg/L free oil
120	Horizontal	Bed depth = 1.2-1.8 m Anthracite, sand Dia. = 3.7 m (max) Flow rate = 27 300-54 500 m^3/d Feed pressure = 1 030 kPa Length = 21.3 m (max)	200-300 mg/L Tss	remove 200-250 mg/L
117	Deep Bed	Loading rate = 100-200 $m^3/m^2{\cdot}d$	1 000 mg/L (max)	can removal all SS to particle size = 0.1-50 μm
120	Deep Bed	Bed depth = 1.2-1.8 m Anthracite, sand Flow rate = 16 400 m^3/d Feed pressure = 1 0303 kPa (or 9.1-10.7 m of head)	>100 mg/L TSS	can remove up to 200-250 mg/L TSS
20	Graded Density	Loading rate = 250 - 290 $m^3/m^2{\cdot}d$		
114	Vertical Pressure	Coal, sand, garnet infl. Flow rate = 5 700 m^3/d		
118	Mixed Media	Flow = 2 180 - 3 300 m^3/d Ave. flow = 3 200 m^3/d Garnet sand, mixed media	200 mg/L TSS	outlet turbidity = 0.15 0.30 NTU
120	Upflow	Bed depth = 1.8-2.4 m Loading rate = 350 - 390 $m^3/m^2{\cdot}d$	200-250 mg/L TSS	can remove up to 200-250 mg/L TSS
20	Ultra high	Total depth = 2.1 m Loading rates = 880 - 1 170 $m^3/m^2{\cdot}d$	200 mg/L TSS	10-20 mg/L TSS

rejection (%). These parameters indicate the membrane's permeability to water and to dissolved solids respectively. The following are typical operating parameters for an RO system (117):

- Cellulose-Acetate membrane (0.1 mm thickness)
- Maximum water flux = 0.35 - 0.88 $m^3/m^2 \cdot d$ at 5000 mg/L TDS
- Salt rejection = 90-98%
- Maximum feedwater salt concentration = 5000 - 50 000 mg/L
- Maximum membrane life = 1-2 years
- Maximum operating pressure = 4060 - 5080 kPa
- Maximum feedwater temperature = 40°C
- Operating pH range = 3-8

Some examples of RO system design and performance from the power generation industry are given in Tables E.47 and E.48.

Electrodialysis (ED) differs from RO and UF in that it moves the dissolved salts away from the water, instead of the other way around (20). The practical advantage is that the quantity of minerals is far less than that of the water that contains them (20). The other major difference is that ED removes only ionic species (121). ED devices comprise paired sets of parallel membranes, with an electric field applied perpendicular to the direction of flow of wastewater (20). In each pair of membranes, the one closer to the negative electrode permits passage of positive ions; the other, negative ions (20). A schematic diagram is shown in Figure E.47. Pressure required for ED is about 800 kPa (100 psia) (20). For ionic dissolved solids below 10 0000 mg/L ED performance is comparable to that of RO.

(i) Evaporation. Evaporation involves the removal of water from a mixture by the addition of energy, producing a vapour and a low volume, highly concentrated "bottoms" stream. In geographical areas where net annual evaporation exceeds precipitation natural evaporation ponds have been used to concentrate wastewater. In mechanical evaporation the vapour from the process can be condensed to improve energy efficiency and yield high quality water.

Mechanical evaporation process variations include vapour compression, vertical tube falling film, multiple effect, and flash evaporation (1,20,30). The various processes offer advantages in energy efficiency, capital cost, resistance to scaling and fouling, degree of concentration of the bottoms and total dissolved solids concentration in the effluent. Some examples of mechanical evaporator operating and performance data

TABLE E.47 SOME EXAMPLES OF REVERSE OSMOSIS SYSTEM DESIGN AND PERFORMANCE FROM THE POWER GENERATION INDUSTRY

Ref.	Type	Flow Rate (m^3/d)	Water Flux ($m^3/m^2 \cdot d$)	Pressure (kPa)	Removal Efficiency	Comments
118		3 000		2760-4140		
116	Spiral Wound	1 100	0.11	2760-4140	TDS (4358 to 222)	
125	Spiral Wound	13 600	-	-	-	(1)
	Spiral Wound	4 900	-	-	-	
	Hollow Fiber	2 180	-	-	-	(2)
126	Hollow Fiber	2 040	-	2 400	90% Salt	
127	-	980-1090			TDS 426 → 15 mg/L (Cl^-) = 26 → 0 mg/L (SiO_2) = 30 → 0.65 mg/L $CaCO_3)$ = 358 → 17mg/L	(3)
128	Spiral Wound	13 600	0.35-0.43	2 750	divalent ions > 99% monovalent ions = 95% SiO_2 = 85-91%	(4)
129	Cellulose Acetate Membrane	-	0.59	4 140	(6)	(5)
129	Aromatic Polyamide Membrane	-	0.15	4 140	(6)	(5)
129	NS-100 Membrane	-	0.44	4 140	(6)	(5)

Comments:
(1) RO used for water reuse.
(2) Supplies boiler makeup water.
(3) Pilot plant, RO in series with demineralizer for boiler makeup.
(4) Pilot plant.
(5) Lab scale jar tests terminated at 67% water recovery.
(6) See Table E.48.

TABLE E.48 REVERSE OSMOSIS SYSTEM CONTAMINANT REMOVAL (129)

Parameters	RO Influent (mg/L)	Cellulose Acetate (mg/L)	Aromatic Polyamide (mg/L)	NS-100* (mg/L)
K	17.9	1.98	0.48	2.84
Na	82.9	13.3	7.0	13.3
Ca	73.3	0.05	0.1	0.2
Mg	87.1	0.8	0.4	2.4
Zn	20.8	0.01	0.01	0.02
Fe	7.8	2.0	0.8	0.5
CrO_2^{2-}	55.3	5.4	0.9	2.0
Cl^-	135.3	37.7	6.9	0.0
SiO_2	48.1	20.9	2.7	12.0
SO_4^{2-}	1 200.0	95.0	0.14	0.05
Inorganic PO_4	15.0	1.4	0.14	0.05
Organic PO_4	76.5	0.05	0.23	0.09
Inorganic C	11.8	2.9	2.8	6.8
Organic C	12.3	2.8	9.1	8.6
Operating pH range		4-8	4-10	2-12

* Microporous polysulfone support coated with ultra-thin layer of polyethylenimine which is cross-linked with m-tolulene 2,4-diisocyanate.

are shown in Tables E.49 and E.50. As indicated in Table E.49 vapour compression evaporation (VCE) is widely used in the power generation industry. A VCE system is shown in Figure E.48.

Various types of evaporators are used for waste volume reduction and wastewater treatment at nuclear power stations. AECL compared the advantages and limitations of different kinds of evaporators for liquid wastes at Chalk River Nuclear Laboratories (Table E.51).

For the nuclear application the performance of an evaporator is described by the decontamination factor (DF), which may be defined as the ratio of the influent and effluent activities (excluding tritium). Decontamination factors for evaporators have been reported variously as around 10^2 to 10^4, and 10^4 to 10^6 although in theory DFs of more than 10^6 could be expected. Decontamination factors of 10^4 have been reported by

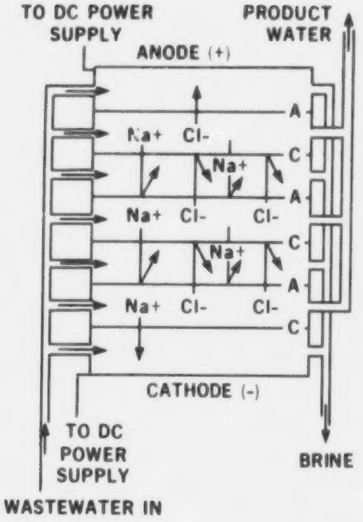


FIGURE E.47 SCHEMATIC OF ELECTRODIALYSIS SYSTEM (20)

AECL for a wiped film evaporator. However, evaporators will not remove tritium or ruthenium due to their volatility (1). Commercially available evaporators and evaporator/crystallizers can, in general, accommodate feed flows from as low as 0.2 L/s to as high as 2 L/s. TDS concentration in the feed should ideally be greater than 1000 mg/L to achieve the greatest decontamination factors (DF) and bottoms concentrations. However, any TDS concentration higher than that practical for processing through ion exchange would be suitable for an evaporator.

(j) Sludge Treatment. Ash handling, flue gas desulphurization, and most of the unit wastewater treatment processes described previously generate inorganic sludges. These are normally discharged from the process as a clarifier underflow at between one and 10 percent solids. Concerns relating to sludge transportation costs, land (disposal site) costs, groundwater contamination, reclamation of landfills, and water reuse generally dictate that these sludges be further dewatered.

Sludge thickening can be achieved using mechanical or non-mechanical systems. Lagoons are commonly used to both store and thicken sludges. However, mechanical thickeners, which are similar to clarifiers, are preferred, since more consistent thickening can be achieved. Typical design criteria for sludge thickeners are available in the literature (135, 136). Most inorganic sludges can be thickened to between 5 and 15% solids.

TABLE E.49 MECHANICAL EVAPORATOR OPERATING AND PERFORMANCE DATA FROM THE POWER GENERATION INDUSTRY*

Ref.	Evaporator Type	Specifications	Effluent Quality
118	Long-tube, vertical falling film vapour compression evaporator (VCE)	Inflow rate = 1 800 m^3/d Brine output = 185 m^3/d Recovered water output = 1 600 m^3d	
79	Vapour compression evaporator	Inflow rate = 940 m^3/d Brine output = 20 m^3/d Recovered water output = 920 m^3/d	<10 mg/L TDS
116	Long-tube, vertical falling-film VCE	Feed rate = 820-950 m^3/d Recovered water output = 740-900 m^3/d	See Table E.50
130	VCE	Capacity = 980 m^3/d	salt removal = 98%
117	Vapour compression distillation	90% water recovery Energy requirements = 24 kWh/m^3	10 mg/L TDS
20	VCE	Capacity = 140-190 m^3/d	
131	VCE	Inflow rate = 3 000 m^3/d Brine output = 270 m^3/d Recovered water output = 2 700 m^3/d	
132	Vertical tube evaporation (VTE) pilot plant	Upflow = 18.9 m^3/d Tube length = 3.0 m Tube dia. = 5.1 cm (OD) Operating temp. = 99°C Optimum operating temp. = 82°C	
133	Vapour-compression distillation	Total design raw feed rate = 1900 m^3/d Brine output = 11-16 Feed temp. = 98.3°C Product temp = 98.3°C Steam consumption = 440 kg/d	See Table E.50

*Typical influent contains 10 000 mg/L TDS

TABLE E.50 CONTAMINANT REMOVAL BY MECHANICAL EVAPORATORS

Ref.	Parameter	Influent (mg/L)	Effluent (mg/L)
VCE Ion Removal			
116			
	Ca	782	< 1
	Mg	189	< 1
	Na	985	< 1
	$CaCO_3$	0	0
	SO_4^{2-}	4 453	< 1
	Cl	231	< 1
	SiO_2	62	0.013
	TDS	7 109	1.5-3
	TSS	20-25	< 1
	pH	6.39	6.5
VCD Contaminant Removal			
133			
	Pentachlorophenol	< 1	< 1
	phenol	1.3	0.7
	1,3 dichlorobenzene	-	< 1
	hexachloropentadiene	< 1	< 1
	Sb	7	3
	As	49	< 1
	Be	< 0.5	< 0.5
	Cd	< 0.5	< 0.5
	Cr	5	< 1
	Cu	2 700	10
	Pb	7	< 3
	Hg	1.5	2
	Ni	2.5	1
	Se	< 2	< 2
	Ag	15	2
	Th	< 1	< 1
	V	1 000	590
	Zn	910	6
	CN^-	24	1.9
	TOC (mg/L)	29	< 20

Further increases in sludge solids concentration can be effected by the use of mechanical dewatering devices. The most commonly used equipment includes centrifuges, vacuum filters, filter belt presses and pressure filters. Design data for dewatering equipment are available in the literature (135, 136, 137). Generally, sludges from the powergeneration industry can be dewatered to between 15 and 50% solids. Table E.52

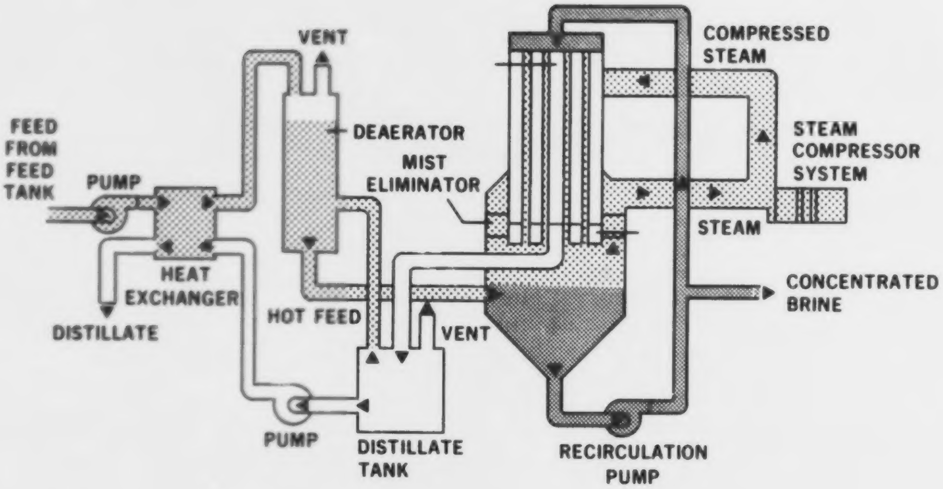

VENT
COMPRESSED STEAM
FEED FROM FEED TANK
PUMP
DEAERATOR
MIST ELIMINATOR
STEAM COMPRESSOR SYSTEM
STEAM
HEAT EXCHANGER
DISTILLATE
HOT FEED
VENT
CONCENTRATED BRINE
PUMP
DISTILLATE TANK
RECIRCULATION PUMP

FIGURE E.48 VAPOUR COMPRESSION EVAPORATION SYSTEM (134)

shows typical sludge dewatering practices and performance from the power generation industry.

(k) Carbon Adsorption. Adsorption involves the accumulation of soluble and quasi-soluble components of a solution at a solid/solution interface. In the field of wastewater treatment, adsorption involves the contacting of a wastewater stream with an adsorbent for the purpose of removing some of the undesirable substances from the wastewater. These substances accumulate on the absorbent and are recovered or destroyed by treating the absorbent in a suitable manner.

Although many absorbents have been used for wastewater treatment, activated carbon has been the most popular for practical applications. The medium is a porous structure of granular or powdered carbon that provides a high internal surface area. Activated carbon adsorption has very limited use in the power generating industry. It is used specifically to remove problem organic compounds or soluble oil. Wastewater must be pretreated to a high degree since free oil can cause coating and suspended solids can cause clogging of the carbon units (110).

The degree to which activated carbon will remove specific organics by adsorption is influenced by the solubility of the specific organic material in the

TABLE E.51 COMPARISON OF AVAILABLE EVAPORATORS FOR RADIOACTIVE LIQUID WASTE TREATMENT (1)

Evaporator	Major Advantage	Major Limitation	Suitable for Foamy CRNL* Wastes
Coil	Low Cost	Unsuitable for foaming liquids	No
Natural Circulation Horizontal Tube or Vertical Tube	Relatively inexpensive	Unsuitable for foaming liquids	No
Forced Circulation	High heat transfer coefficient	Possible plugging of tube inlets	Yes
Thermosiphon	High heat transfer coefficient with dilute feeds	Concentration of high solids feed	Yes
Vapour Compression	High heat economics	Uneconomical for small flows	No
Multiple-effects	Same as vapor compression		
Falling Film	Suitable for foaming liquids	Difficulty in achieving uniform feed distribution which leads to fouling	Yes
Rising Film	Suitable for foaming liquid	Cannot handle large solids	No
Flash	Ecomomical for large scale plant	Unsuitable for scaling liquids	No
Wiped Film	Suitable for foaming and scaling liquids	High evaporation cost	Yes

* Chalk River Nuclear Laboratories (AECL)

wastewater and the affinity of the particular organic for activated carbon. Since many sulphur compounds are polar, they adsorb onto the surface of activated carbon. However, since the organics in a waste stream compete with sulphur compounds for available adsorption sites, the effectiveness of sulphur removal depends upon the characteristics of a particular wastewater (141).

Activated carbon systems usually take the form of an adsorption bed or column using granular carbon. However, activated carbon in powdered form can be added directly to a waste stream; an example is the addition of powdered carbon to the aeration tanks of an activated sludge system (142).

TABLE E.52 TYPICAL SLUDGE DEWATERING PRACTICES AND PERFORMANCE IN THE POWER GENERATION INDUSTRY

Ref.	Type	Specifications	Feed Conc. (%)	Cake Discharge Solids (%)
113	Rotary Drum Filter (Vacuum Filter)	Drum diameter = 1.83 m Design vacuum level = 70 kPa Design vacuum capacity = 3 070 $m^3/m^2 \cdot d$ Operating filtration rate = 1 500 $kg/m^2 \cdot d$ Revolution time = 5 minutes	10 wt%	40-47 wt%
124	Continuous Belt Vacuum Filter	Loading rate = 470 $kg/m^2 \cdot d$ Vacuum = 68 kPa Cycle time = 5 min Operation = 7 h/d, 5 d/wk Vacuum capacity = 3 500 $m^3/m^2 \cdot d$	8-14 wt%	68-72 wt% moisture
138	Rotary Vacuum Filter Filter Press	Drum diameter = 1.8 m Design vacuum = 69 kPa Filter area = 17.8 m^2 (total) Operating pressures	8 wt% (lime treated wastewater)	30 wt%
		= 690 - 860 kPa (lime treated WW)	8 wt%	50 wt%
		= 1 400 - 1 550 kPa (caustic treated WW)	1.9 wt%	30 wt%
139	Vacuum Drum Belt Filter	Drum diameter = 0.91 m Loading rate = 590-1 170 $m^3/m^2 \cdot d$ Vacuum = 64 kPa Revolution time = 2-4 min	3.1-14.8 wt%	35 wt%
140	Belt Press	Solids loading = 40 kg/h (normal operation)	7-12%	60-71%

Calgon Filtrasorb 400 granulated activated carbon has been tested at bench scale on cooling tower blowdown (CTB) and air preheater effluent (APE) (133). Organic contaminant removal data from this test are presented in Table E.53. The design surface loading rate for this study was 120 $m^3/m^2 \cdot d$.

TABLE E.53 BENCH SCALE REMOVAL OF ORGANICS USING ACTIVATED CARBON ADSORPTION (133)

Parameter	Station & Type	Influent (g/L)	Effluent (g/L)
Benzene	Plant 1: CTB	< 1	<1
	Plant 1: APE	2.0	<1
	Plant 2: CTB	1.5	<1
	Plant 2: APE	< 1	<1
Toluene	Plant 1: CTB	23.5	3.0
	Plant 1: APE	3.5	2.0
	Plant 2: APE	< 1	N.D.
Ethylbenzene	Plant 1: APE	< 1	<1
Chloroform	Plant 1 APE	< 1	N.D.
	Plant 2: CTB	2.4	N.D.
	Plant 2: APE	< 1	<1
	Plant 3: CTB	< 1	N.D.
Bromodichloromethane	Plant 2: CTB	2.4	<1
	Plant 3: CTB	8.2	<1
Dibromochloromethane	Plant 2: CTB	< 1	N.D.
	Plant 3: CTB	58.5	N.D.
	Plant 3: APE	< 1	N.D.

(l) Ion Exchange. In the ion exchange process, ions in a solution are exchanged for ions of the same charge on the resin through which the solution flows (143). Regeneration of the resin with an acid or alkaline medium results in a smaller volume of highly concentrated ions which may be more amenable to other treatment or recovery methods (111, 144). Ion exchange is particularly appropriate where high quality water is required for reuse/recycle applications (20) and for reducing heavy metal concentrations (111, 144), including radionuclides. In recent years, highly selective synthetic ion exchange resins have been developed to remove specific ions from solutions. Since ion exchange is a competitive process (ions compete with each other for removal), each application should be evaluated individually (141).

The ion exchange system most frequently employed in the treatment of radioactive liquid waste is the mixed bed system, which consists of a stationary bed containing mixed anion and cation resins (1). When ionic contaminants begin to appear in the bed effluent, the bed may be regenerated or, more commonly with radioactive streams, it may be discarded and replaced with fresh resin. Combination filters/ion exchangers, which are not regenerated, are also commonly used.

Average values of decontamination factors (DF) in nuclear applications for ion exchange columns have been reported variously as about 100 and in the range of 10^2-10^3 (1). (The DF may be defined as the reduction in radiation fields due to reduction in radioactivity. It is also defined as the ratio of radioactivities in the influent and effluent streams associated with treatment processes.)

(m) Tritium Removal System. In a tritium removal system (TRS) being designed for application to CANDU stations, tritium is removed from heavy water in two steps, as shown in Figure E.49 (1). In the first step, the tritium is transferred from heavy water by vapour phase catalytic exchange (VPCE) with deuterium gas. The heavy water is evaporated, superheated to 200°C and mixed with deuterium gas before passing over a catalyst bed, where the following exchange reaction transfers tritium from the heavy water vapour to the deuterium gas.

$$DTO + D_2 = D_2O + DT$$

In the second step, the D_2 and DT are cooled to -250°C and tritium is separated from deuterium by cryogenic distillation.

Figure E.50 shows a more detailed schematic of the tritium removal process. The heavy water feed is withdrawn from the moderator downstream of the purification system and is sent to the two TRS feed tanks on a batch basis. Each one of the feed tanks is capable of holding one day's supply for the TRS. From the feed tanks, heavy water is fed at a continuous rate of 360 kg/h to the TRS.

The heavy water is vaporized and degassed to remove volatile impurities before flowing to the VPCE step. The VPCE consists of eight stages connected in series. Each stage contains an evaporator, superheater, a catalyst vessel and a condenser. The deuterium gas flows countercurrent to the heavy water in the overall VPCE, but flows co-current to heavy water within a stage. The gas is circulated to the cryogenic unit by a liquid-ring compressor.

The cryogenic unit contains four distillation columns in series where tritium is concentrated to 99% T_2 gas in the final column. The cryogenic columns operate at

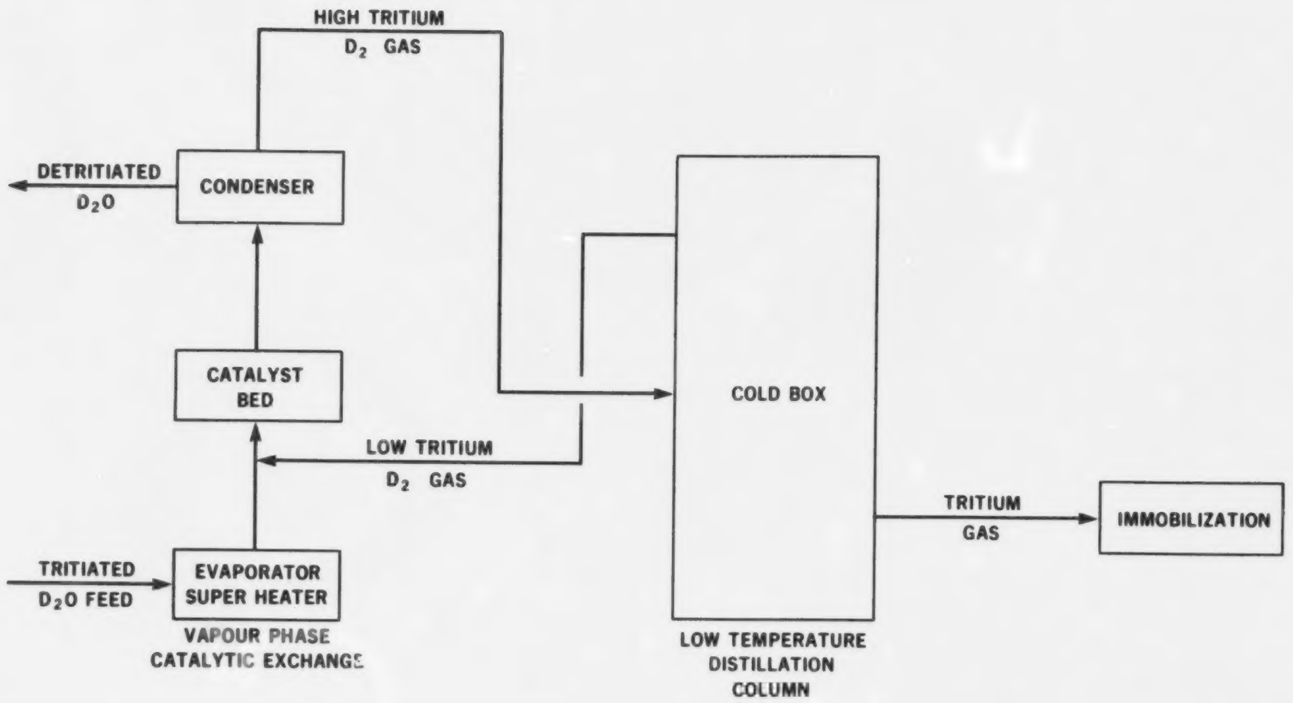

HIGH TRITIUM
D_2 GAS
DETRITIATED
D_2O
CONDENSER
CATALYST
BED
LOW TRITIUM
D_2 GAS
TRITIATED
D_2O FEED
EVAPORATOR
SUPER HEATER
VAPOUR PHASE
CATALYTIC EXCHANGE
COLD BOX
LOW TEMPERATURE
DISTILLATION
COLUMN
TRITIUM
GAS
IMMOBILIZATION

FIGURE E.49 TRITIUM REMOVAL SYSTEM COMPONENTS (1)

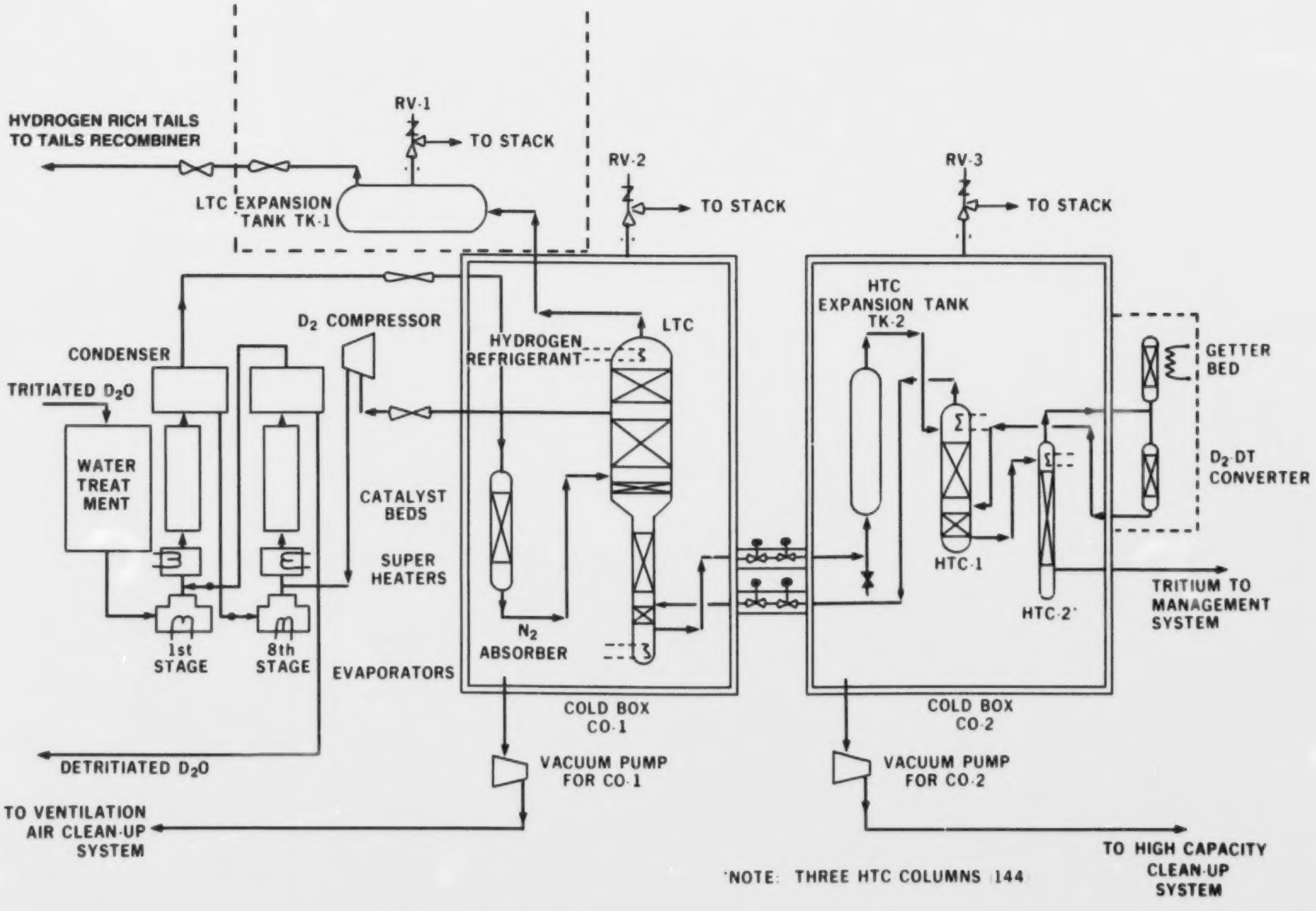

HYDROGEN RICH TAILS TO TAILS RECOMBINER
RV-1
TO STACK
LTC EXPANSION TANK TK-1
RV-2
TO STACK
RV-3
TO STACK
CONDENSER
D$_2$ COMPRESSOR
TRITIATED D$_2$O
WATER TREAT MENT
CATALYST BEDS
SUPER HEATERS
1st STAGE
8th STAGE
EVAPORATORS
HYDROGEN REFRIGERANT
LTC
N$_2$ ABSORBER
COLD BOX CO-1
VACUUM PUMP FOR CO-1
DETRITIATED D$_2$O
TO VENTILATION AIR CLEAN-UP SYSTEM
HTC EXPANSION TANK TK-2
HTC-1
HTC-2*
GETTER BED
D$_2$-DT CONVERTER
TRITIUM TO MANAGEMENT SYSTEM
COLD BOX CO-2
VACUUM PUMP FOR CO-2
TO HIGH CAPACITY CLEAN-UP SYSTEM
*NOTE: THREE HTC COLUMNS 144

FIGURE E.50 TRITIUM REMOVAL SYSTEM SCHEMATIC (1)

approximately -250°C and are kept at this temperature by a liquid hydrogen refrigerant in highly insulated cold boxes maintained at a vacuum of 10^{-3} Pa or lower. The power input of the refrigeration unit is 1 550 kW. Hydrogen and helium are the only two fluids suitable for providing the very low temperature of refrigeration required. Helium has the advantage of being inert. However, it is a superheated gas at 23°K while hydrogen is close to its boiling point. This lends a great thermodynamic advantage to hydrogen since its latent heat of vaporization can be efficiently utilized in the reboilers and condensers of the distillation columns. Since hydrogen isotopes are to be handled in the TRS routinely, the use of hydrogen as the refrigerant does not significantly increase the hazard.

The tritium gas produced in the final column of the cryogenic unit is 99% pure. This gas is withdrawn in 17.5 L batches (corresponding to 1 809 TBq) and immobilized on titanium metal as a tritide (metal hydride). The immobilized tritium is contained in a storage vessel which is designed to store 20 100 TBq of tritium. The vessel is sized to accommodate the decay product helium over its design lifetime and to be heated to its maximum design temperature without exceeding the vessel design pressure. After completion of immobilization, the storage vessels are stored in a specially constructed vault in the TRS building. The tritium may be disposed of or, more likely, sold as a feed product for experimental fusion reactors or other purposes.

(n) Biological Treatment. Biological treatment processes are generally based on the ability of commonly occurring aerobic (oxygen-requiring) bacteria to oxidize organic carbon-containing wastes, producing carbon dioxide, water and more bacterial cells. In this application the process is known as "secondary" treatment.

Biological processes are generally used only to treat sanitary wastes at power generation facilities which do not have access to municipal sewage treatment facilities. A number of biological treatment systems, including rotating biological contactors, oxidation ditches, extended aeration, and conventional activated sludge systems are commonly used and are capable of producing effluent quality of 20 mg/L BOD_5 and 25 mg/L suspended solids (145). These units are often available as package units suitable for power generation stations. Excellent information concerning package plants and biological treatment in general is available in the literature (145-151).

(o) Other Processes. Other waste treatment processes for non-radioactive and radioactive liquid wastes have been and continue to be researched and developed. The most common demonstrated technologies have been described in the foregoing sections.

E.5.3 Treatment Systems for Specific Wastewaters. Examples of power plant treatment systems designed for specific wastewater streams are described in the following sections.

(a) Coal Pile Runoff. Ontario Hydro's Lakeview G.S., operates a treatment facility exclusively for its coal pile drainage. At this station, all coal pile drainage is collected and routed, by both pumping and gravity flow, to a transfer station and on to a concrete lagoon. Automatic lime dosing equipment in the transfer station partially neutralizes the wastewater prior to the lagoon. Final pH adjustment is made at the lagoon (33).

The treatment lagoon has two cells so that one cell may be cleaned out while the other is in service. One end of the lagoon has sloped sides to allow the accumulated dewatered solids to be removed. Underdrains at the bottom facilitate the dewatering of settled solids. The solids can be returned to the coal pile. The treated effluent from the lagoon is intended to be reused at the station, probably for coal pile dust suppression (33).

In a study (33) of the treatability of coal pile drainage at Canadian steam electric stations, it was found that relatively simple physical-chemical treatment reduced chromium, copper, nickel and zinc concentrations to less than 0.5 mg/L and reduced iron to less than 1 mg/L. For eastern coal pile drainage samples, the most effective treatment was pH adjustment using lime and the addition of an anionic polyelectrolyte as a coagulant aid. For western coal pile drainage samples, the most effective treatment was the addition of either calcium chloride or lime as a primary coagulant; however, in some instances an anionic polyelectrolyte was required to improve the settling properties of the particulates (33). The results of several of these studies are shown in Table E.54 (33).

(b) Ash Transport Water. Because ash ponds are often designed to have an ash disposal capacity for the duration of the plant life, they are usually very large. If the retention time for ash transport water in these ponds is more than 24 hours, suspended solids in the effluent might be expected to be about 30 mg/L or less depending on the ash. However, further treatment, such as sidestream softening, may be necessary to prevent scaling in recirculating ash transport water systems. In addition, it may be necessary to treat the blowdown from a recirculating system before discharge, to meet effluent criteria. Because of the high concentrations of hardness, sulphate and silica in ash pond water, lime-soda softening appears to be a promising treatment process. Other treatment processes such as reverse osmosis, electrodialysis or ion exchange probably would be required for additional dissolved solids removal for complete reuse (152).

TABLE E.54 RESULTS OF LABORATORY TREATABILITY STUDIES ON COAL PILE DRAINAGE FROM A NUMBER OF CANADIAN GENERATING STATIONS (33)

			Parameter Concentration mg/L					
		pH	Suspended Solids	Iron	Chromium	Copper	Nickel	Zinc
Dalhousie G.S.	Untreated	1.2		17 600.	2.0	8.0	7.8	14.5
Lime addition, settling	Treated	7.7		0.74	<0.04	<0.04	<0.08	< 0.02
Lingan G.S.	Untreated	2.1	180.	500.	<0.05	0.56	1.5	5.4
Lime + 0.25 mg/L anionic polymer, settling	Treated	8.2	2.	0.4	<0.05	0.11	<0.1	0.16
Battle R.G.S.	Untreated	7.0	18.80	9.8	0.13	0.82	0.17	0.4
500 mg/L $CaCl_2$, settling	Treated	7.9	10.0	0.5	<0.05	0.22	<0.1	0.18
Milner G.S.	Untreated	8.5	2920.	23.2	<0.01	0.22	<0.1	0.33
250 mg/L Lime, settling	Treated	10.3	4.	0.28	<0.01	0.03	<0.1	0.06

The addition of an alkali may be required to neutralize acidic ash waters. In some situations, chemical flocculation in suitably designed clarifers may be required to treat recirculating ash transport water. The Martin Drake power plant in Colorado Springs, Colorado successfully used this approach. A flow diagram of this system appears in Figure E.51 (119).

Recent treatability studies (153, 154) indicate that laboratory simulated recycled ash transport water can be effectively treated for metals removal by pH adjustment and in some cases polymer addition. Tables E.55 and E.56 show the results of treatability work on eastern Canadian simulated ash recycle transport water for bottom ash and combined bottom/fly ash systems. The effects of chemical precipitation on a range of contaminants in acidic ash waters are shown. After pH adjustments, polymer addition had little incremental effect in improving treatments for these samples. Generally, iron, chromium, copper, nickel and zinc concentrations were less than 0.5 mg/L in treated wastewaters.

(c) Boiler Chemical Cleaning Wastewaters. Boiler cleaning wastes are difficult to treat by chemical precipitation methods because chelating agents are often used to improve the removal of iron and copper and to fix these metals in the cleaning solution (155). Precipitation of heavy metals in a chemical cleaning solution where chelates are used requires that first the chelating action be broken. Once this has been accomplished the metal solubility is decreased and the metals can be removed by chemical precipitation (155).

The procedure for chelant breaking will vary with the cleaning solution. For hydroxy acetic-formic and citric acid cleaners, neutralization with lime or caustic above a pH of 11.5 will break the chelant and will precipitate iron and copper to meet the 1 mg/L level. The neutralized effluent settles rapidly, producing an acceptable overflow clarity from the settling tank. The sludge will also dewater satisfactorily on a rotary vacuum belt filter if the wastewater is neutralized with lime, since a granular precipitate is formed. However, if the waste is neutralized with sodium hydroxide, the precipitate is only marginally dewatered on a rotary vacuum filter. In this case, unless ash-laden wastewaters are mixed with the cleaning wastes, more successful dewatering will occur with a recessed plate filter press (155).

Ammoniated citric acid and EDTA are another group of cleaners. Ammonia is the primary chelant. Procedures used to break the chelant include high lime dosages, ammonia stripping, sodium sulphite conditioning and treatment in a large ash pond. The

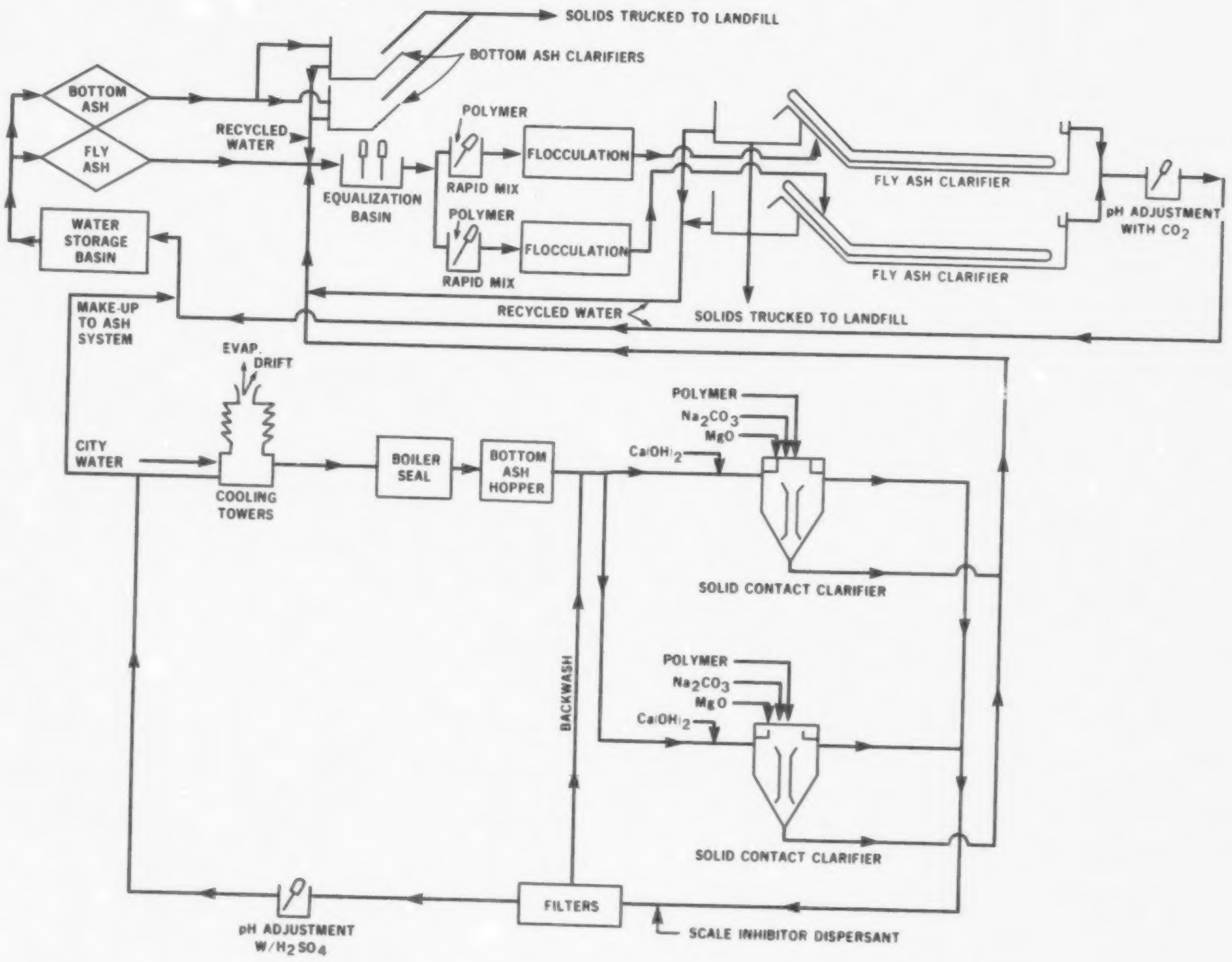

SOLIDS TRUCKED TO LANDFILL
BOTTOM ASH CLARIFIERS
BOTTOM ASH
FLY ASH
RECYCLED WATER
WATER STORAGE BASIN
EQUALIZATION BASIN
POLYMER
RAPID MIX
FLOCCULATION
POLYMER
RAPID MIX
FLOCCULATION
FLY ASH CLARIFIER
FLY ASH CLARIFIER
pH ADJUSTMENT WITH CO_2
RECYCLED WATER
SOLIDS TRUCKED TO LANDFILL
MAKE-UP TO ASH SYSTEM
EVAP.
DRIFT
CITY WATER
COOLING TOWERS
BOILER SEAL
BOTTOM ASH HOPPER
POLYMER
Na_2CO_3
MgO
$Ca(OH)_2$
SOLID CONTACT CLARIFIER
BACKWASH
POLYMER
Na_2CO_3
MgO
$Ca(OH)_2$
SOLID CONTACT CLARIFIER
pH ADJUSTMENT W/H_2SO_4
FILTERS
SCALE INHIBITOR DISPERSANT

FIGURE E.51 FLOW DIAGRAM OF ASH WASTEWATER TREATMENT SYSTEM (MARTIN DRAKE G.S.) (119)

TABLE E.55 RESULTS OF LABORATORY TREATABILITY STUDIES USING SIMULATED RECIRCULATING BOTTOM ASH TRANSPORT WATER FROM AN EASTERN CANADIAN GENERATING STATION (153, 154)

Parameter	Control pH = 3.7		pH 9* no Polymer		pH 9* and Polymer		pH 8* and Polymer	
	Total	Dissolved	Total	Dissolved	Total	Dissolved	Total	Dissolved
Ag	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
Al	20.3	19.6	< 0.01	< 0.01	< 0.01	< 0.01	0.04	0.02
B	1.04	1.04	1.02	1.01	0.982	1.01	1.05	1.05
Ba	0.036	0.038	0.022	0.067	0.023	0.038	0.029	0.036
Be	0.0031	0.0032	< 0.0005	< 0.0005	< 0.0005	< 0.0005	< 0.0005	< 0.0005
Ca	223	220	231	228	218	220	238	237
Cd	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02
Co	0.26	0.27	< 0.05	< 0.05	< 0.05	< 0.05	0.10	0.08
Cr	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01
Cu	0.485	0.463	< 0.009	0.020	< 0.009	< 0.009	< 0.009	< 0.009
Fe	0.38	0.37	0.03	0.05	0.05	0.04	0.05	0.05
K	52	51	53	53	52	54	56	56
Mg	25.4	25.3	24.2	24.4	21.2	22.3	22.5	23.3
Mn	6.24	6.30	1.36	2.02	2.07	2.13	3.9	4.12
Mo	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3
Na	50	48	133	129	129	133	128	126
Ni	1.84	1.89	0.25	0.32	0.37	0.36	0.74	0.7
P	< 0.6	0.7	< 0.6	< 0.6	< 0.6	< 0.6	< 0.6	< 0.6
Pb	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
Si	39.9	39.6	20.0	17.7	19.3	17.1	23.9	20.1
Sr	1.37	1.37	1.36	1.32	1.34	1.32	1.34	(1.34)
Th	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01
Ti	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
V	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
Zn	0.71	0.77	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	0.06
Zr	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	0.50

All results reported in mg/L.
*pH adjusted with sodium hydroxide.

TABLE E.56 RESULTS OF LABORATORY TREATABILITY STUDIES USING SIMULATED RECIRCULATING COMBINED BOTTOM AND FLY ASH TRANSPORT WATER FROM AN EASTERN CANADIAN GENERATING STATION (153, 154)

	Control pH = 4.0		pH 9* no Polymer		pH 9* and Polymer		pH 8* and Polymer	
Parameter	Total	Dissolved	Total	Dissolved	Total	Dissolved	Total	Dissolved
Ag	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
Al	182	182	0.54	0.25	0.25	1.13	0.14	0.15
B	14.3	14.4	12.5	12.7	11.8	12.9	12.6	12.7
Ba	0.022	0.030	< 0.005	0.009	< 0.005	0.012	< 0.005	0.041
Be	0.0424	0.0423	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< .005
Ca	446	452	393	398	385	387	393	410
Cd	0.30	0.28	0.03	0.05	0.03	0.03	0.03	0.05
Co	0.42	0.37	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
Cr	0.09	0.08	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01
Cu	1.51	1.55	< 0.009	< 0.009	< 0.009	< 0.009	< 0.009	< 0.009
Fe	0.56	0.54	< 0.01	0.01	0.04	< 0.01	0.02	0.05
K	294	309	298	295	284	302	295	290
Mg	81.5	77.4	61.5	60	46.1	47.1	54.7	60.2
Mn	8.45	7.99	0.6	1.2	0.28	0.72	1.43	1.65
Mo	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.3
Na	376	406	919	902	883	957	875	841
Ni	3.12	2.98	0.08	0.09	0.09	0.07	0.09	0.10
P	1.1	0.8	< 0.6	< 0.6	< 0.6	< 0.6	< 0.6	< 0.6
Pb	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
Si	60.1	60.8	0.53	0.91	0.69	0.81	1.17	1.34
Sr	6.57	6.56	5.63	5.44	5.17	5.42	5.46	5.47
Th	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01
Ti	0.047	0.042	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< .005
V	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< .005
Zn	8.26	7.81	0.08	0.08	0.07	0.07	0.09	0.09
Zr	0.19	0.18	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05

All results reported in mg/L

pH adjusted using sodium hydroxide.

ash pond treatment may be effective if long term contact (60 to 120 days) with alkaline ash can be ensured (155).

Hydrochloric acid cleaners and ammoniated bromate solutions can be treated effectively with either lime or sodium hydroxide. Heavy metals are precipitated by elevating pH to 9 (155).

Once the chelant is broken and metal precipitation occurs, settling can be enhanced with a polymeric flocculating agent. The design of the clarifier is important; a solids contact clarifier usually facilitates settling. The settled sludge can be concentrated by a number of means, usually either a rotary vacuum filter or a recessed plate filter press. Granular-media filters may be used on the clarified effluent to further reduce suspended solids. A typical flow diagram of a chemical cleaning wastes treatment system is shown in Figure E.52 (155).

(d) Blowdown from Evaporative Recirculating Cooling Systems. Blowdown from recirculating cooling systems can be treated by a number of methods depending upon a plant's overall wastewater management scheme. If a source of high quality water is desired, vapour compression evaporation (VCE) may be used. A schematic of VCE treatment of cooling tower blowdown is shown in Figure E.53 (20). Another approach is to use a side stream treatment system on a recirculating cooling system. The Martin Drake power station in Colorado uses a side stream warm lime-soda ash softening process to control the concentations of calcium, magnesium and silica, eliminating the need for blowdown discharge. This subsystem can be seen in Figure E.51.

Several methods exist for removing hexavalent chromium in cooling tower blowdown, such as chromate reduction systems, ion exchange, electrochemical processes and vapor compression evaporation. A chromate reduction system is shown in Figure E.54. In this process, the pH of the blowdown water is adjusted to 2, usually with sulphuric acid, and a reducing agent, such as sulphur dioxide, is added to reduce the hexavalent chromium to the trivalent state. Caustic or lime is then added to raise the pH to 8.5 and form insoluble chromic hydroxide. This process is capable of removing chromium to levels of less than 0.05 mg/L (18).

(e) Radioactive Wastewaters (excluding tritium). Treatment of wastewaters to reduce the concentration of many radionuclides is facilitated by some of the same technologies already described for the reduction of conventional chemical contaminants. Technologies such as ion exchange, filtration, evaporation, ultrafiltration and reverse osmosis have been used at least to some extent by the nuclear industry to treat radioactive wastewaters (20).

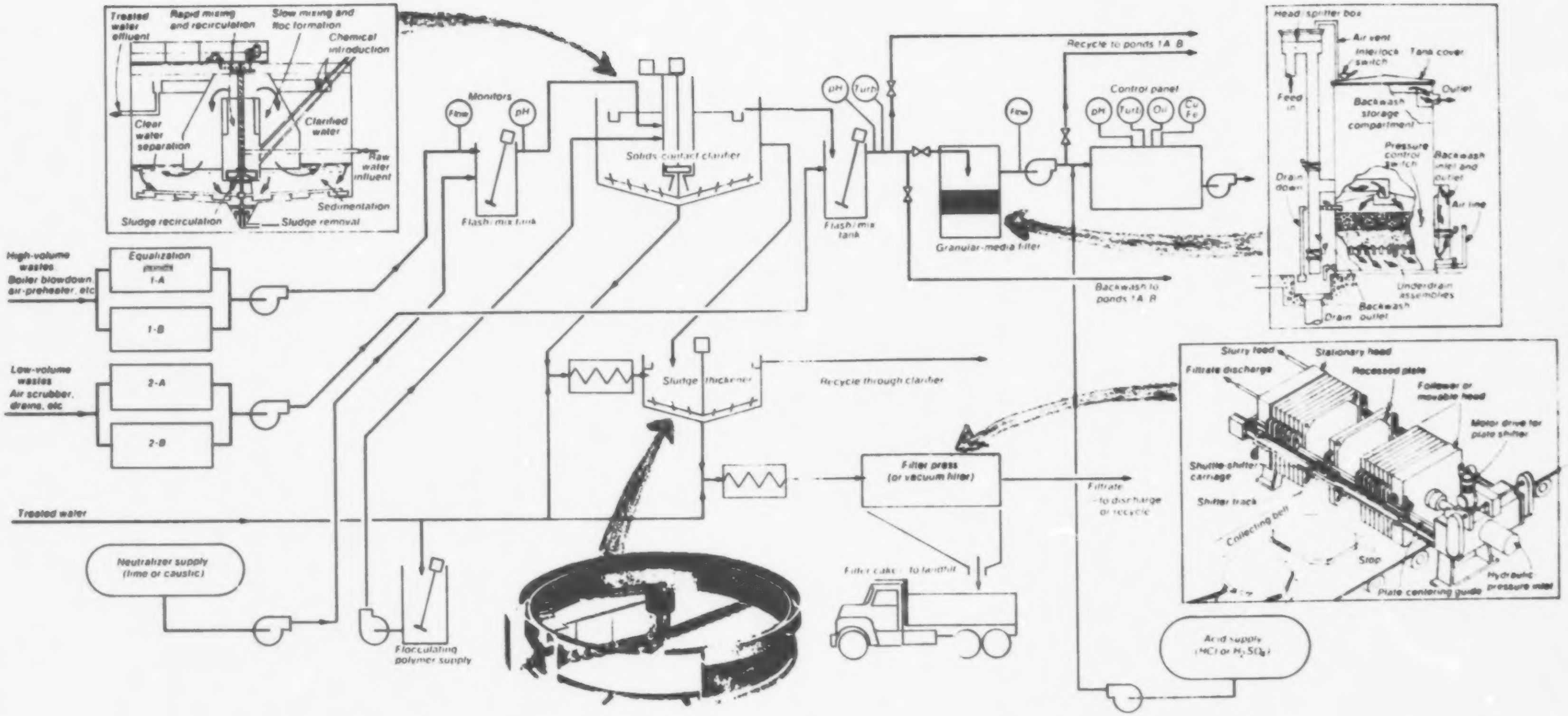

Treated water effluent
Rapid mixing and recirculation
Slow mixing and floc formation
Chemical introduction
Clear water separation
Clarified water
Raw water influent
Sedimentation
Sludge recirculation
Sludge removal
High-volume wastes
Boiler blowdown, air-preheater, etc
Equalization ponds
1-A
1-B
Low-volume wastes
Air scrubber, drains, etc
2-A
2-B
Treated water
Neutralizer supply (lime or caustic)
Flocculating polymer supply
Monitors
Flow
pH
Flash/mix tank
Solids contact clarifier
Sludge thickener
Recycle through clarifier
pH
Turb
Flash/mix tank
Granular-media filter
Flow
Recycle to ponds 1A B
Control panel
pH
Turb
Oil
Cu Fe
Backwash to ponds 1A B
Filter press (or vacuum filter)
Filtrate - to discharge or recycle
Filter cake - to landfill
Acid supply (HCl or H2SO4)
Head/splitter box
Air vent
Interlock switch
Tank cover
Outlet
Feed in
Backwash storage compartment
Pressure control switch
Backwash inlet and outlet
Drain down
Air line
Underdrain assemblies
Backwash outlet
Drain
Slurry feed
Stationary head
Filtrate discharge
Recessed plate
Follower or movable head
Motor drive for plate shifter
Shuttle-shifter carriage
Shifter track
Collecting belt
Stop
Plate centering guide
Hydraulic pressure inlet

FIGURE E.52 BOILER CHEMICAL CLEANING WASTE TREATMENT SYSTEM (155)

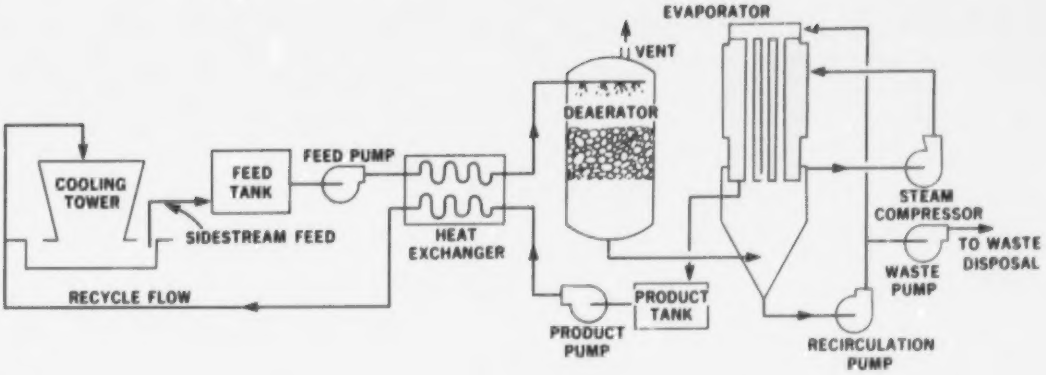

EVAPORATOR
VENT
DEAERATOR
COOLING TOWER
FEED TANK
FEED PUMP
SIDESTREAM FEED
HEAT EXCHANGER
RECYCLE FLOW
STEAM COMPRESSOR
TO WASTE DISPOSAL
WASTE PUMP
PRODUCT TANK
PRODUCT PUMP
RECIRCULATION PUMP

FIGURE E.53 COOLING TOWER BLOWDOWN BRINE CONCENTRATION SYSTEM (20)

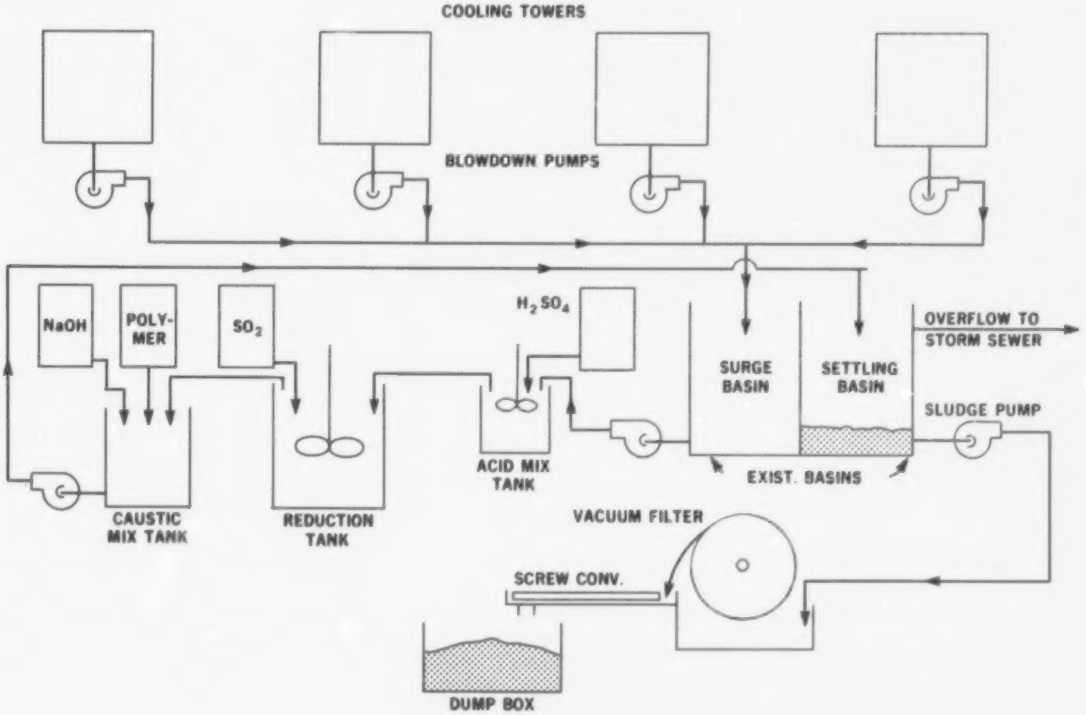

COOLING TOWERS
BLOWDOWN PUMPS
NaOH
POLY-MER
SO_2
H_2SO_4
OVERFLOW TO STORM SEWER
SURGE BASIN
SETTLING BASIN
SLUDGE PUMP
ACID MIX TANK
EXIST. BASINS
CAUSTIC MIX TANK
REDUCTION TANK
VACUUM FILTER
SCREW CONV.
DUMP BOX

FIGURE E.54 COOLING TOWER BLOWDOWN CHROMATE REDUCTION SYSTEM (18)

Although many of the same treatment technologies are used, equipment designs may differ somewhat from those used for conventional pollutants. For example, disposable cartridge filters are used to remove suspended solids down to 75 micrometre size (20). Etched disk filters are also used. These can be cleaned and reused, thus producing less radioactive solid waste than disposable cartridge filters (1). Ion exchange (IX) units have been used at both CANDU and U.S. power stations. In CANDU stations spent IX resins are not regenerated, whereas in the U.S. they may be (20). Recently, reverse osmosis (RO) units have been used in U.S. stations for processing laundry waste and floor drains (20).

Evaporators are used to remove both dissolved and suspended non-volatile radionuclides. Forced circulation designs tend to predominate to prevent flashing and scaling in heating tubes. Equipment may be divided among several locations to reduce personnel exposure to radiation during maintenance. Evaporators generally have 1.6 to 2.2 L/s capacities and are used redundantly to assure continuous operation (20).

The various treatment processes previously described may be combined to form alternative wastewater treatment systems in nuclear power stations. System design will depend on the various wastewater characteristics, the effluent criteria to be attained, and the comparative economics and engineering feasibility of various alternative systems which might be considered. The liquid radioactive waste system for a nuclear station in the United States shown in Figure E.55 is an example of an integrated wastewater treatment system design (1). The system shows wastewater segregation, filtration, ion exchange and evaporation of various types of wastestreams.

Wastewaters generated in Japanese boiling water reactors (BWRs) are generally classified into four types according to their conductivity and radioactivity: equipment liquid waste, floor liquid waste, chemical liquid waste and laundry liquid waste (1). The first three types of wastewaters are reused as feed water to the station after filtration, concentration and demineralization. If no laundry wastes were released, a closed liquid water system would be established, resulting in no wastewater discharges. Since foaming can occur in evaporators holding laundry wastes containing commercial detergents, other techniques are currently being investigated. The use of foamless detergents in an evaporator, wiped film vertical drier, and an incineration system are being investigated. A schematic of a radioactive laundry waste treatment system is shown in Figure E.56 (1).

Atomic Energy of Canada Ltd. (AECL) has investigated and demonstrated a number of radioactive liquid waste treatment processes at the Chalk River Nuclear Laboratories (CRNL). A simplified schematic of the waste treatment system being

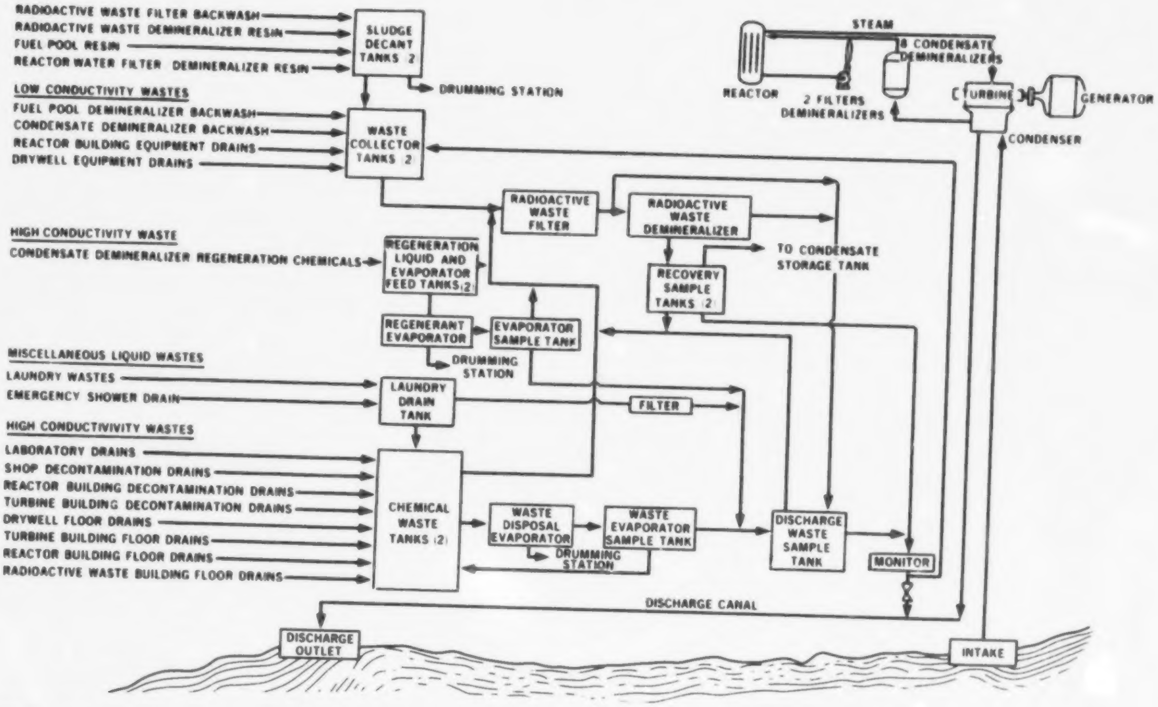

RADIOACTIVE WASTE FILTER BACKWASH
RADIOACTIVE WASTE DEMINERALIZER RESIN
FUEL POOL RESIN
REACTOR WATER FILTER DEMINERALIZER RESIN
SLUDGE DECANT TANKS (2)
DRUMMING STATION
LOW CONDUCTIVITY WASTES
FUEL POOL DEMINERALIZER BACKWASH
CONDENSATE DEMINERALIZER BACKWASH
REACTOR BUILDING EQUIPMENT DRAINS
DRYWELL EQUIPMENT DRAINS
WASTE COLLECTOR TANKS (2)
STEAM
REACTOR
2 FILTERS DEMINERALIZERS
8 CONDENSATE DEMINERALIZERS
TURBINE
GENERATOR
CONDENSER
RADIOACTIVE WASTE FILTER
RADIOACTIVE WASTE DEMINERALIZER
TO CONDENSATE STORAGE TANK
HIGH CONDUCTIVITY WASTE
CONDENSATE DEMINERALIZER REGENERATION CHEMICALS
REGENERATION LIQUID AND EVAPORATOR FEED TANKS (2)
RECOVERY SAMPLE TANKS (2)
REGENERANT EVAPORATOR
EVAPORATOR SAMPLE TANK
DRUMMING STATION
MISCELLANEOUS LIQUID WASTES
LAUNDRY WASTES
EMERGENCY SHOWER DRAIN
LAUNDRY DRAIN TANK
FILTER
HIGH CONDUCTIVIVITY WASTES
LABORATORY DRAINS
SHOP DECONTAMINATION DRAINS
REACTOR BUILDING DECONTAMINATION DRAINS
TURBINE BUILDING DECONTAMINATION DRAINS
DRYWELL FLOOR DRAINS
TURBINE BUILDING FLOOR DRAINS
REACTOR BUILDING FLOOR DRAINS
RADIOACTIVE WASTE BUILDING FLOOR DRAINS
CHEMICAL WASTE TANKS (2)
WASTE DISPOSAL EVAPORATOR
WASTE EVAPORATOR SAMPLE TANK
DRUMMING STATION
DISCHARGE WASTE SAMPLE TANK
MONITOR
DISCHARGE CANAL
DISCHARGE OUTLET
INTAKE

FIGURE E.55 TREATMENT SYSTEMS FOR RADIOACTIVE WASTEWATERS (1)

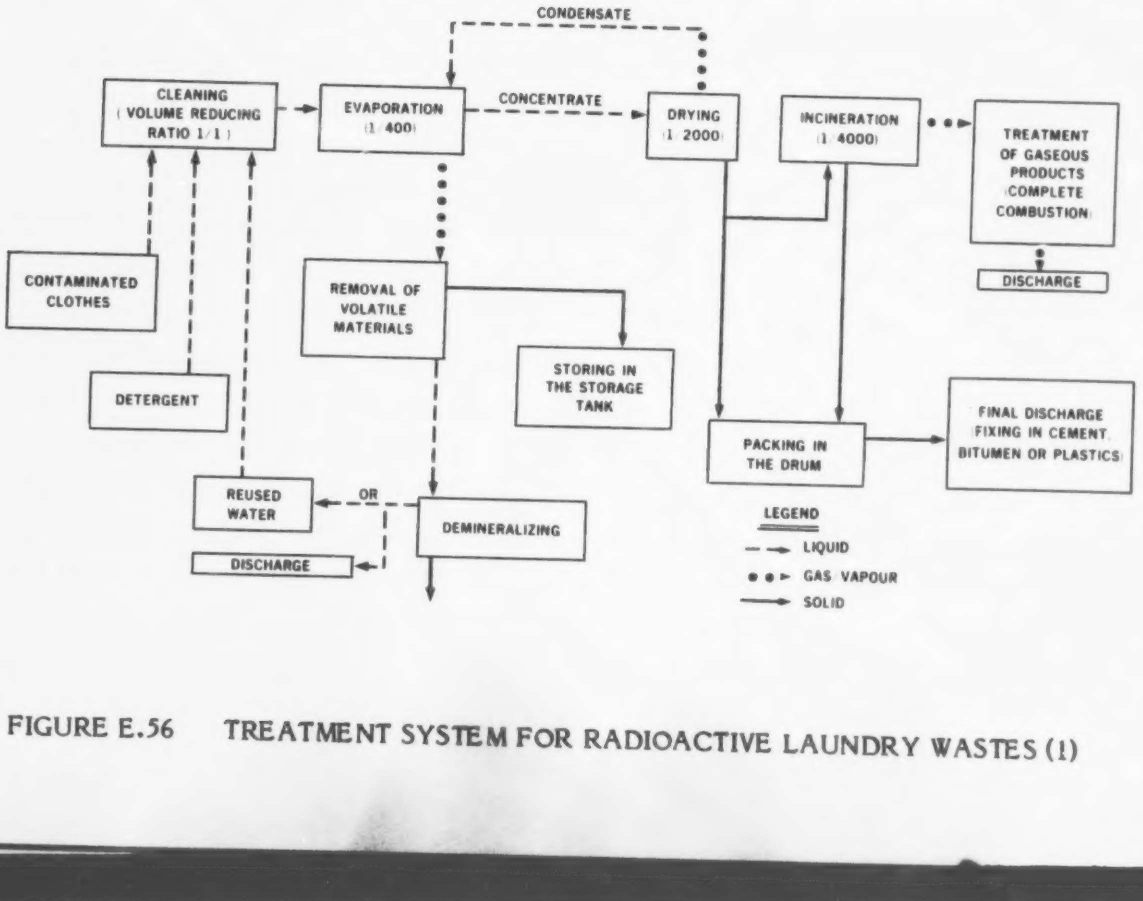

CONDENSATE
CLEANING (VOLUME REDUCING RATIO 1/1)
EVAPORATION (1/400)
CONCENTRATE
DRYING (1/2000)
INCINERATION (1/4000)
TREATMENT OF GASEOUS PRODUCTS (COMPLETE COMBUSTION)
DISCHARGE
CONTAMINATED CLOTHES
DETERGENT
REMOVAL OF VOLATILE MATERIALS
STORING IN THE STORAGE TANK
PACKING IN THE DRUM
FINAL DISCHARGE (FIXING IN CEMENT, BITUMEN OR PLASTICS)
REUSED WATER
OR
DEMINERALIZING
DISCHARGE
LEGEND
LIQUID
GAS VAPOUR
SOLID

FIGURE E.56 TREATMENT SYSTEM FOR RADIOACTIVE LAUNDRY WASTES (1)

investigated is shown in Figure E.57. The system is being designed for quantities of waste equivalent to those generated from three 600-MW(e) CANDU generation stations. Reverse osmosis units are used to concentrate the wastewater (shown in Figure E.58) before feeding the retenate to a wiped film evaporator for further concentration and bituminization of the waste residue. The main focus of the AECL work is volume reduction and immobilization, rather than wastewater treatment to produce very low activity effluent. However, low activity effluent will result due to the removal of the radionuclides in the aqueous wastes (1).

E.5.4 Examples of Wastewater Treatment Systems for Power Plants

Examples of some full scale treatment systems are described in the following sections. Factors which influence the selection of wastewater treatment systems at power plants include:

(1) raw water characteristics,
(2) wastewater characteristics,
(3) effluent limitations, and
(4) whether the wastestream is to be reused or discharged.

(a) Oil/Gas Generating Stations. An oil-fired plant located on the east coast of the U.S. has an overall treatment system as shown in Figure E.59 (20). In this design the various wastewaters are separated into three groups. One group consists of ash and metal cleaning wastewaters. Wet fly ash is cycled continuously between the precipitator and a sump. The flow rate is chosen to maintain desired ash concentration. The sump discharges to a flash-mix tank where acid or caustic is added to achieve proper pH and is then routed to a solids contact clarifier, where polymer addition enhances flocculation and settling of ash. Additional pH adjustment and settling are provided in two settling basins if necessary, before discharge. Sludge from the clarifier underflow is pumped to a vacuum filter for dewatering to about 30% solids by weight (20). For annual metal cleaning operations, the 2270 m^3 settling basin is removed from the line and used to accept cleaning wastes. For treatment, wastes are pumped from the basin to the clarifier, and from there directly to the smaller settling basin (20).

The second group consists of demineralizer and polisher wastewater flows which are collected in another basin and neutralized as a batch. Caustic is added by sidestream recirculation at the basin. When proper pH is achieved the flow joins the clarifier effluent. End-of-pipe instrumentation monitors turbidity, oil and grease and pH before discharge (20).

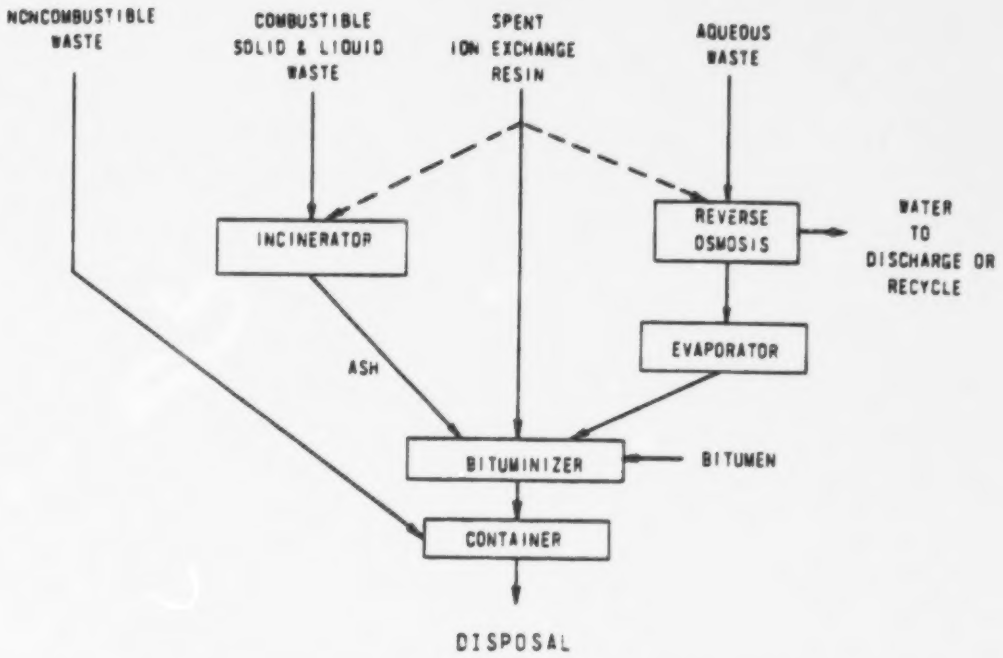

NONCOMBUSTIBLE WASTE
COMBUSTIBLE SOLID & LIQUID WASTE
SPENT ION EXCHANGE RESIN
AQUEOUS WASTE
INCINERATOR
REVERSE OSMOSIS
WATER TO DISCHARGE OR RECYCLE
EVAPORATOR
ASH
BITUMINIZER
BITUMEN
CONTAINER
DISPOSAL

FIGURE E.57 INTEGRATED WASTE TRANSPORT SYSTEM (AECL) (1)

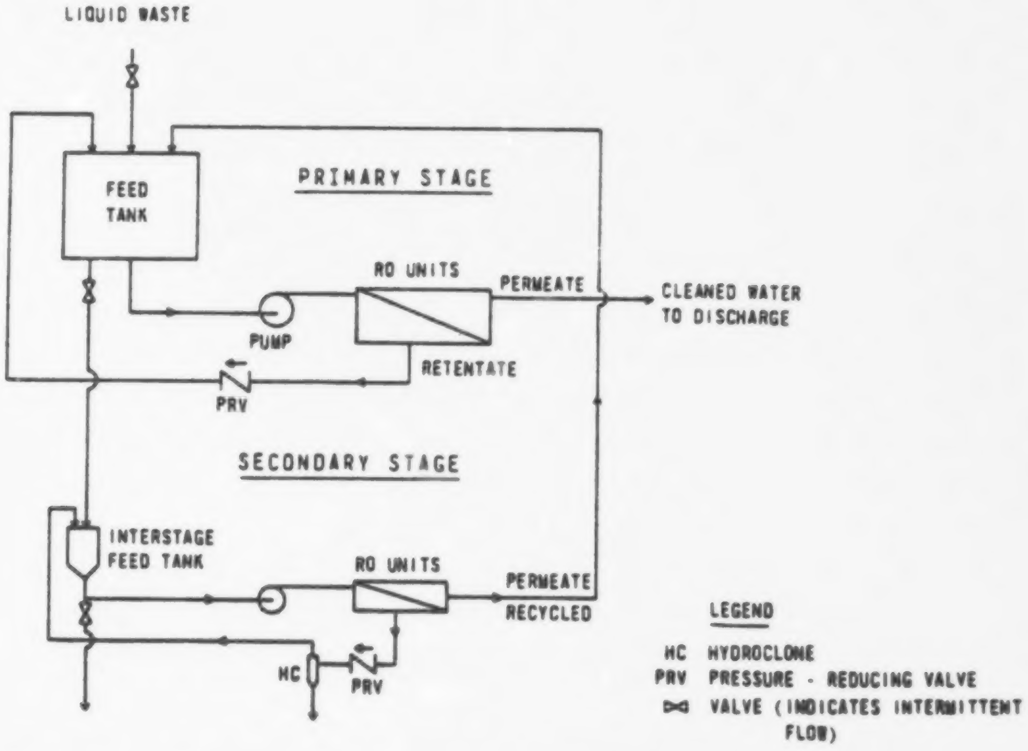

LIQUID WASTE
FEED TANK
PRIMARY STAGE
RO UNITS
PERMEATE
CLEANED WATER TO DISCHARGE
PUMP
RETENTATE
PRV
SECONDARY STAGE
INTERSTAGE FEED TANK
RO UNITS
PERMEATE RECYCLED
HC
PRV
LEGEND
HC HYDROCLONE
PRV PRESSURE - REDUCING VALVE
⋈ VALVE (INDICATES INTERMITTENT FLOW)

FIGURE E.58 REVERSE OSMOSIS RADIOACTIVE WASTEWATER TREATMENT SUB-SYSTEM (AECL) (1)

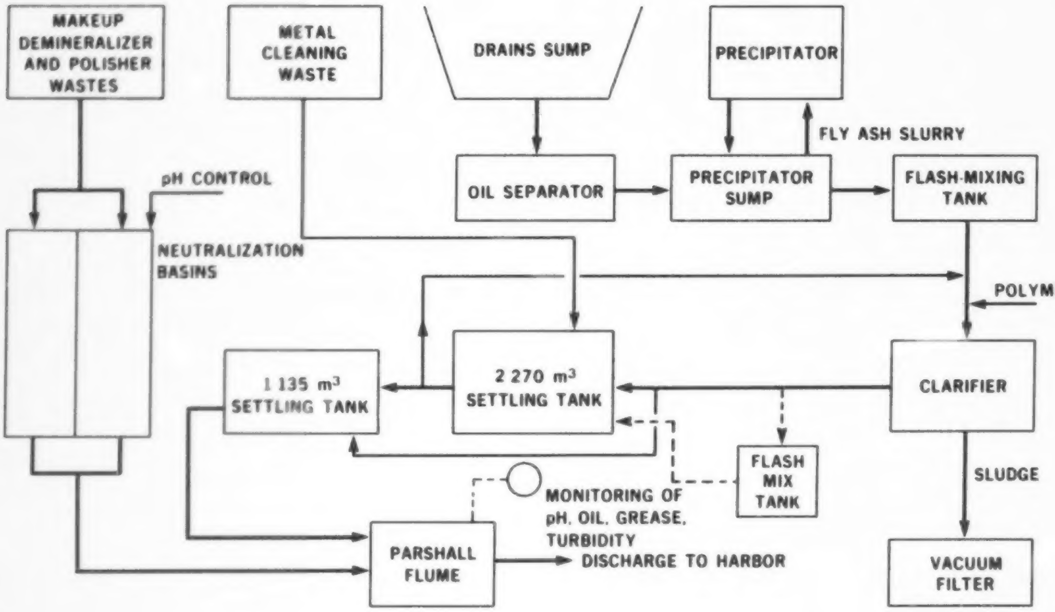

MAKEUP DEMINERALIZER AND POLISHER WASTES
METAL CLEANING WASTE
DRAINS SUMP
PRECIPITATOR
FLY ASH SLURRY
pH CONTROL
OIL SEPARATOR
PRECIPITATOR SUMP
FLASH-MIXING TANK
NEUTRALIZATION BASINS
POLYMER
1 135 m³ SETTLING TANK
2 270 m³ SETTLING TANK
CLARIFIER
FLASH MIX TANK
SLUDGE
MONITORING OF pH, OIL, GREASE, TURBIDITY
PARSHALL FLUME
DISCHARGE TO HARBOR
VACUUM FILTER

FIGURE E.59 INTEGRATED WASTEWATER TREATMENT SYSTEM AT AN OIL-FIRED STATION (20)

The third group is floor, roof and equipment drains which are collected in four sumps and delivered to a gravity-type oil/water separator. Oil and scum are skimmed off at the top, and suspended solids settle to the bottom. Tank effluent is recycled to the wet fly ash sump. Any oil remaining is removed with the ash as it settles out in the clarifier. Oil removed in the separator is returned to day tanks for burning (20).

In case of emergency, as when wastewater limits are exceeded, flow is diverted to a 7600 m^3 lagoon (not shown in Figure E.59) to permit treatment before discharge (20).

The wastewater treatment system at the 1 000-MW oil-fired Coleson Cove G.S. in New Brunswick incorporates neutralization of water treatment plant wastes, oil removal from collected plant drains, settling lagoons, and recirculation capability for effluent which exceeds effluent criteria. The lagoons are sized to hold boiler cleaning wastes. A trickling filter treats sanitary wastes. Yard drains have sedimentation facilities prior to discharge (156).

(b) Coal-Fired Generating Stations. Deerhaven Generating Station near Gainesville, Florida, consists of an 81-MW gas/oil fired unit and a 235-MW coal fired unit. A flow diagram of the wastewater treatment is shown in Figure E.60 (157). Cooling tower makeup is treated by two-stage softening and filtration to reduce cooling tower blowdown which is processed by a brine concentrator. Demineralizer regeneration wastes are also sent to the brine concentrator. Domestic wastes are treated in septic tanks. All other plant wastewaters are sent to the ash pond for use as ash sluice system makeup. Wastewater from the ash pond in excess of that required for ash sluice system makeup is processed by the brine concentrator and spray drier. Although not shown in Figure E.60, oil control equipment is also included in the system (157, 158).

A diagram of the wastewater treatment system for the 200-MW Ray D. Nixon zero-discharge coal-fired power plant near Colorado Springs, Colorado is shown in Figure E.61 (159). All power plant wastewaters flow by gravity to a 1.2 ha earthen basin for equalization of flows and compositions. Wastewater streams flowing into the basin include cooling tower blowdown, ash system blowdown, floor and storm drains and chemical regeneration wastes. Cooling tower blowdown can bypass the basin to conserve heat in winter. The basin is lined with natural clays and can contain approximately 38 million litres.

The filtration system produces high clarity feedwater from combined wastewaters that contain up to 200 mg/L total suspended solids. The system consists of three separate package units, each with a capacity of 19 L/s. A dry cationic polymer flocculant is added to aid filtration (118).

The reverse osmosis (RO) system recovers 50 percent of the filtered effluent for reuse as cooling tower makeup. It consists of three skid-mounted units connected in parallel. Normally, one of the units is on standby. Sulphuric acid and deposit inhibitors are added to the feed for scale control. The wastewater then passes through parallel polishing cartridge filters before entering the RO modules (118).

The concentrate from the RO units is fed to the evaporator system. The evaporator consists of two long-tube vertical falling-film vapor compression evaporators (VCE) which are capable of processing approximately 13 L/s. They recover 90 percent of the combined waste brine feedwater for reuse as demineralizer feed and cooling tower make-up. Since waste brine is concentrated to nearly 30 times the solubilities for $CaSO_4$, $BaSO_4$, SiO_2, and other minor components, the system performs both evaporation and crystallization duties. These components precipitate in a controlled environment inside the condenser tubes and sump to minimize scaling on metal surfaces. With good operating

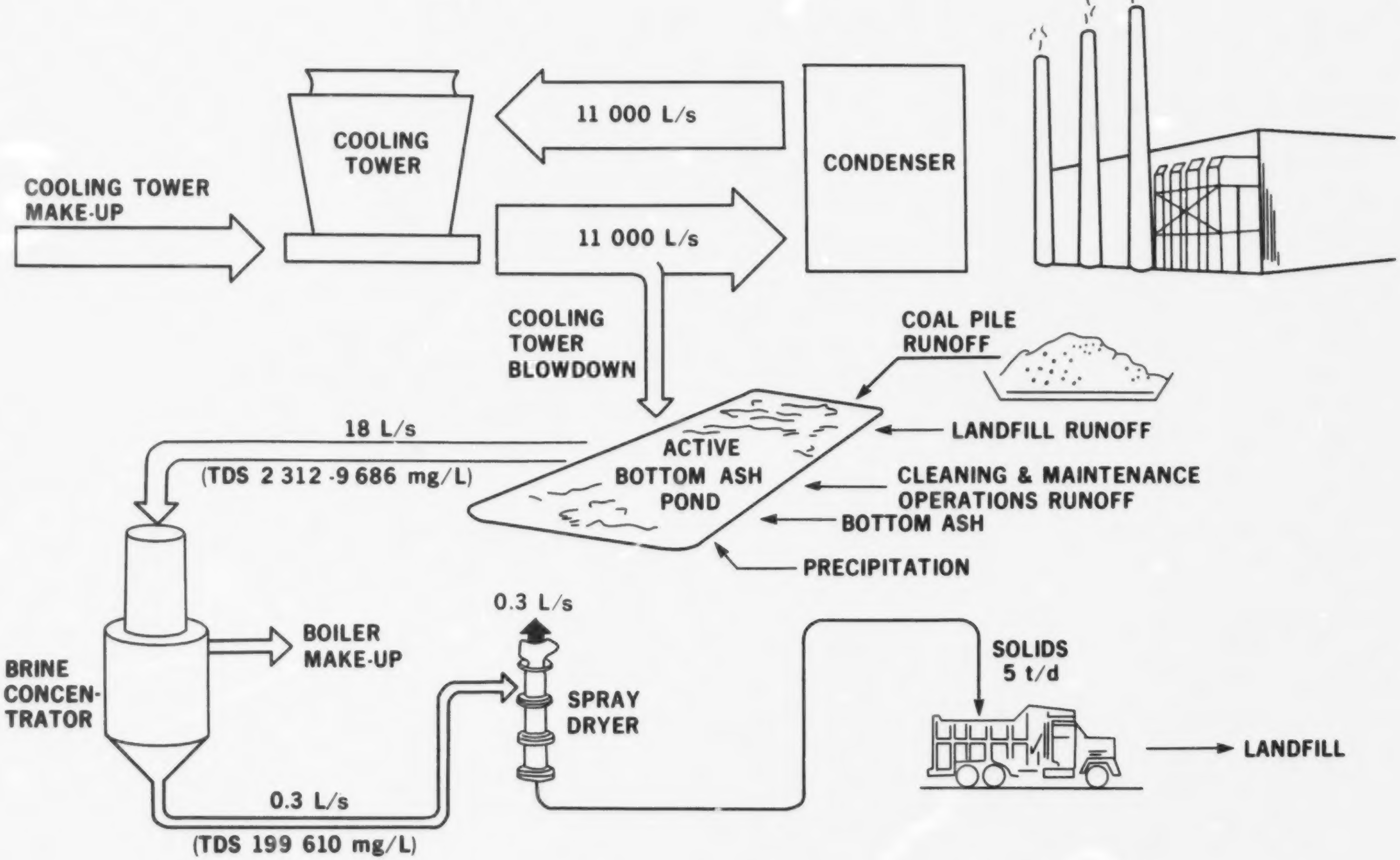

COOLING TOWER MAKE-UP
COOLING TOWER
11 000 L/s
11 000 L/s
CONDENSER
COOLING TOWER BLOWDOWN
COAL PILE RUNOFF
LANDFILL RUNOFF
CLEANING & MAINTENANCE OPERATIONS RUNOFF
BOTTOM ASH
PRECIPITATION
ACTIVE BOTTOM ASH POND
18 L/s
(TDS 2 312 -9 686 mg/L)
BRINE CONCEN-TRATOR
BOILER MAKE-UP
0.3 L/s
(TDS 199 610 mg/L)
0.3 L/s
SPRAY DRYER
SOLIDS 5 t/d
LANDFILL

FIGURE E.60 WASTEWATER TREATMENT SYSTEM AT A GAS/OIL/COAL-FIRED STATION (DEERHAVEN G.S.) (157)

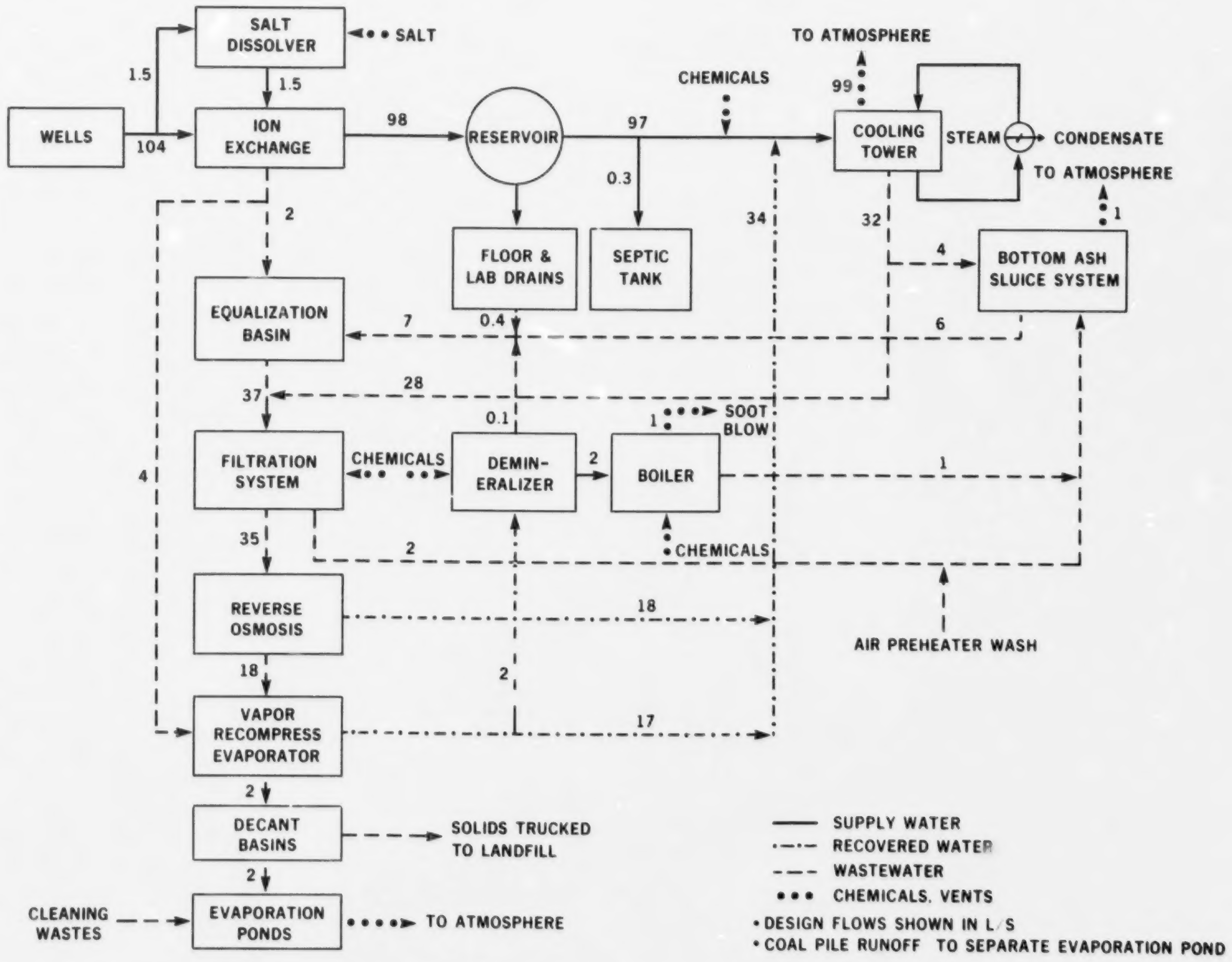

WELLS
1.5
104
SALT DISSOLVER
SALT
1.5
ION EXCHANGE
98
RESERVOIR
97
0.3
CHEMICALS
TO ATMOSPHERE
99
COOLING TOWER
STEAM
CONDENSATE
TO ATMOSPHERE
1
2
FLOOR & LAB DRAINS
SEPTIC TANK
34
32
4
BOTTOM ASH SLUICE SYSTEM
EQUALIZATION BASIN
7
0.4
6
37
28
0.1
1
SOOT BLOW
FILTRATION SYSTEM
CHEMICALS
DEMIN-ERALIZER
2
BOILER
1
4
35
2
CHEMICALS
REVERSE OSMOSIS
18
AIR PREHEATER WASH
18
2
VAPOR RECOMPRESS EVAPORATOR
17
2
DECANT BASINS
SOLIDS TRUCKED TO LANDFILL
2
CLEANING WASTES
EVAPORATION PONDS
TO ATMOSPHERE
SUPPLY WATER
RECOVERED WATER
WASTEWATER
CHEMICALS, VENTS
• DESIGN FLOWS SHOWN IN L/S
• COAL PILE RUNOFF TO SEPARATE EVAPORATION POND

FIGURE E.61 WATER/WASTEWATER ZERO DISCHARGE MANAGEMENT SYSTEM WASTEWATER AT A COAL-FIRED STATION (R.D. NIXON G.S.) (159)

practices, the evaporator system is capable of continuous operation for an extended period of up to one year (118).

Brine slurry wastes from the evaporators are piped to one of the plant's two 10 metre by 30 metre below grade concrete basins to allow solids to settle out. In addition, evaporator ponds are available to handle wastes that cannot be processed by the effluent plant. These ponds have a total surface area of 16 ha, are lined with 20 mil PVC liner and covered with approximately 30 cm of clay-type earth (118).

The wastewater treatment system at the Dalhousie G.S. in New Brunswick combines wastes from a 100-MW oil-fired unit and a 200-MW coal-fired unit. The system, shown in Figure E.62, provides oil separation for plant wastes, flow equalization for plant, ash and coal pile wastewaters. Neutralization and clarification, together with recirculation capability is provided (160).

Figure E.63 shows a possible water/wastewater management system for coal-fired stations. Many of the recommendations of the Design Phase Code are indicated in this figure.

(c) Nuclear Generating Stations. Figure E.64 illustrates a possible water and wastewater management system for a CANDU station. A recirculating cooling system for condenser cooling water could be used, although this is unlikely to be used for CANDU stations located near marine or large fresh water bodies. An intermediate cooling loop between the moderator, other auxiliary coolers and the once-through cooling water is shown.

Conventional suspended solids removal, oil removal, neutralization, and sewage treatment facilities are shown. The sewage treatment system would not be used if raw sewage were discharged to a municipal system.

Active liquid waste treatment facilities are indicated. Alternative system components include filters and ion exchangers, reverse osmosis and evaporators, or evaporators and distillate ion exchange polishers. A possible evaporator/ion exchange polisher system for radioactive wastewater treatment is shown in Figure E.65. All active liquid waste treatment processes will result in waste residues which can be immobilized and stored.

Figure E.64 also shows a tritium removal system (TRS). This is primarily for the treatment of the high tritium content of heavy water from the moderator coolant system. Such a system might also be used for treatment of the primary heat transport system heavy water, although the tritium removal efficiency would be lower because of the lower tritium concentrations in the feed. Tritium in wastewaters produced because of

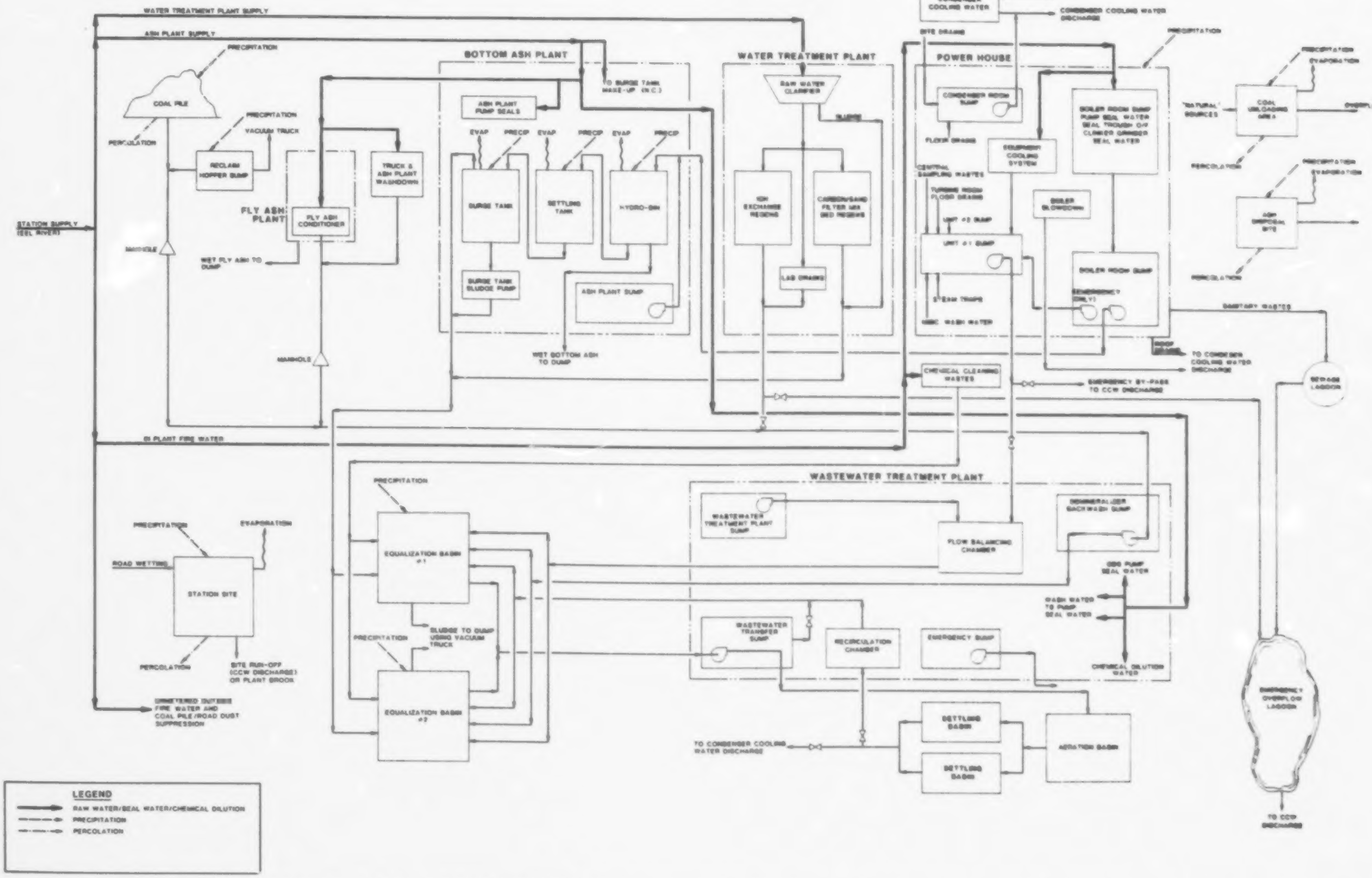

WATER TREATMENT PLANT SUPPLY
ASH PLANT SUPPLY
STATION SUPPLY (EEL RIVER)
PRECIPITATION
COAL PILE
PERCOLATION
PRECIPITATION
VACUUM TRUCK
RECLAIM HOPPER SUMP
FLY ASH PLANT
FLY ASH CONDITIONER
TRUCK & ASH PLANT WASHDOWN
MANHOLE
WET FLY ASH TO DUMP
MANHOLE
IN PLANT FIRE WATER
BOTTOM ASH PLANT
TO SURGE TANK MAKE-UP (N.C.)
ASH PLANT PUMP SEALS
EVAP
PRECIP
EVAP
PRECIP
EVAP
PRECIP
SURGE TANK
SETTLING TANK
HYDRO-BIN
SURGE TANK SLUDGE PUMP
ASH PLANT SUMP
WET BOTTOM ASH TO DUMP
WATER TREATMENT PLANT
RAW WATER CLARIFIER
SLUDGE
ION EXCHANGE REGENS
CARBON/SAND FILTER MIX BED REGENS
LAB DRAINS
CONDENSER COOLING WATER
CONDENSER COOLING WATER DISCHARGE
SITE DRAINS
POWER HOUSE
CONDENSER ROOM SUMP
FLOOR DRAINS
CENTRAL SAMPLING WASTES
TURBINE ROOM FLOOR DRAINS
UNIT #2 SUMP
UNIT #1 SUMP
STEAM TRAPS
MISC. WASH WATER
EMERGENCY COOLING SYSTEM
BOILER BLOWDOWN
BOILER ROOM SUMP PUMP SEAL WATER SEAL TROUGH O/F CLINKER GRINDER SEAL WATER
BOILER ROOM SUMP
EMERGENCY (ONLY)
PRECIPITATION
ROOF DRAINS
TO CONDENSER COOLING WATER DISCHARGE
SANITARY WASTES
SEWAGE LAGOON
CHEMICAL CLEANING WASTES
EMERGENCY BY-PASS TO CCW DISCHARGE
"NATURAL" SOURCES
COAL UNLOADING AREA
PRECIPITATION
EVAPORATION
OVERFLOW
PERCOLATION
PRECIPITATION
EVAPORATION
ASH DISPOSAL SITE
PERCOLATION
PRECIPITATION
EVAPORATION
ROAD WETTING
STATION SITE
PERCOLATION
SITE RUN-OFF (CCW DISCHARGE) OR PLANT BROOK
UNMETERED OUTSIDE FIRE WATER AND COAL PILE/ROAD DUST SUPPRESSION
PRECIPITATION
EQUALIZATION BASIN #1
SLUDGE TO DUMP USING VACUUM TRUCK
PRECIPITATION
EQUALIZATION BASIN #2
WASTEWATER TREATMENT PLANT
WASTEWATER TREATMENT PLANT SUMP
FLOW BALANCING CHAMBER
DEMINERALIZER BACKWASH SUMP
CBS PUMP SEAL WATER
WASH WATER TO PUMP SEAL WATER
CHEMICAL DILUTION WATER
WASTEWATER TRANSFER SUMP
RECIRCULATION CHAMBER
EMERGENCY SUMP
TO CONDENSER COOLING WATER DISCHARGE
SETTLING BASIN
SETTLING BASIN
AERATION BASIN
EMERGENCY OVERFLOW LAGOON
TO CCW DISCHARGE
LEGEND
RAW WATER/SEAL WATER/CHEMICAL DILUTION
PRECIPITATION
PERCOLATION

FIGURE E.62 WASTEWATER TREATMENT SYSTEM AT A COAL-FIRED STATION (DALHOUSIE G.S.) (160)

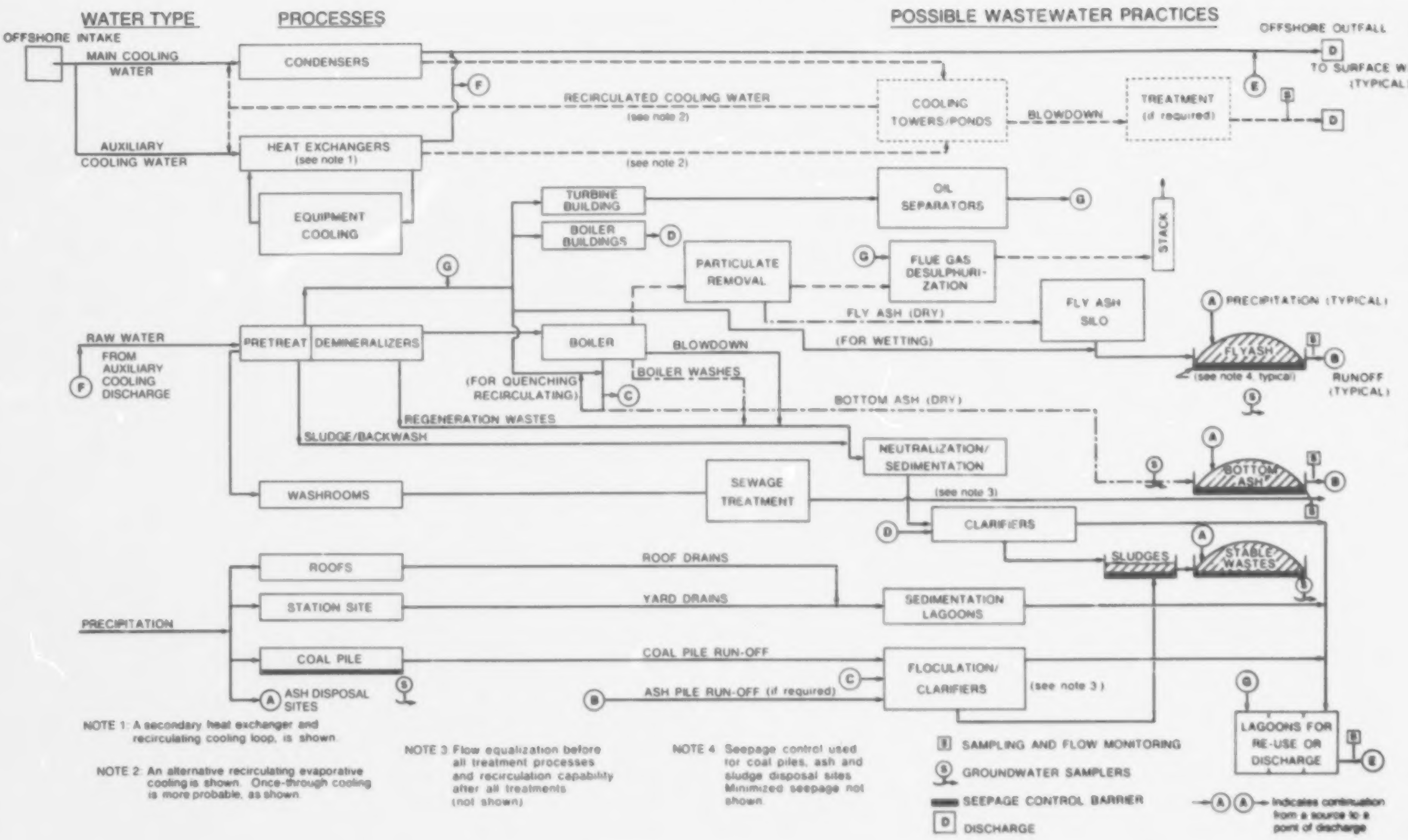
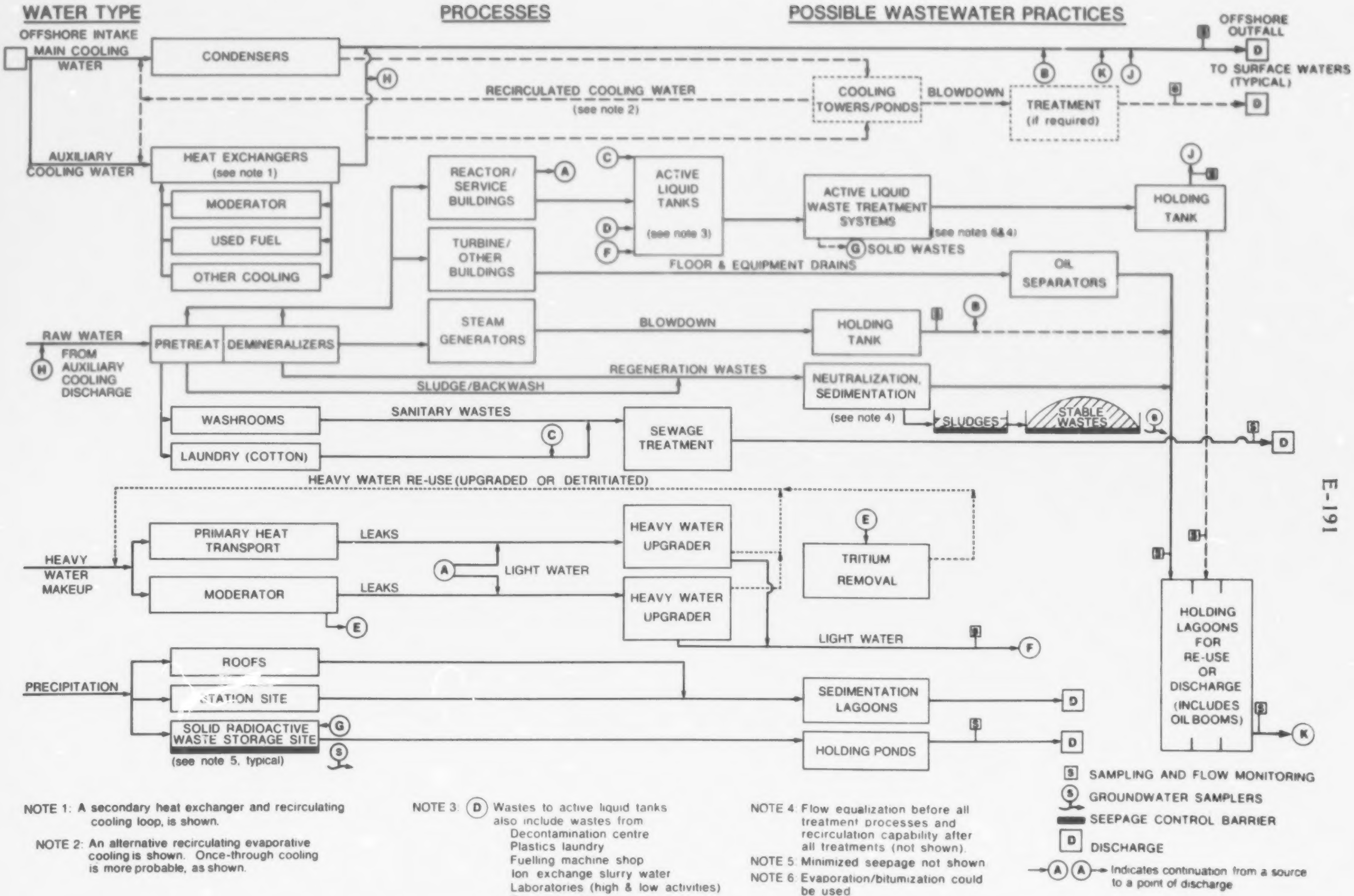

WATER TYPE
PROCESSES
POSSIBLE WASTEWATER PRACTICES
OFFSHORE INTAKE
MAIN COOLING WATER
AUXILIARY COOLING WATER
CONDENSERS
HEAT EXCHANGERS (see note 1)
EQUIPMENT COOLING
F
RECIRCULATED COOLING WATER (see note 2)
(see note 2)
COOLING TOWERS/PONDS
BLOWDOWN
TREATMENT (if required)
OFFSHORE OUTFALL
TO SURFACE WATERS (TYPICAL)
D
E
S
RAW WATER
FROM AUXILIARY COOLING DISCHARGE
PRETREAT
DEMINERALIZERS
G
TURBINE BUILDING
BOILER BUILDINGS
BOILER
OIL SEPARATORS
PARTICULATE REMOVAL
FLUE GAS DESULPHURIZATION
STACK
FLY ASH SILO
FLY ASH (DRY)
(FOR WETTING)
BLOWDOWN
BOILER WASHES
(FOR QUENCHING RECIRCULATING)
C
BOTTOM ASH (DRY)
REGENERATION WASTES
SLUDGE/BACKWASH
NEUTRALIZATION/ SEDIMENTATION
(see note 3)
A
PRECIPITATION (TYPICAL)
FLYASH
(see note 4, typical)
RUNOFF (TYPICAL)
B
BOTTOM ASH
WASHROOMS
SEWAGE TREATMENT
CLARIFIERS
SLUDGES
STABLE WASTES
PRECIPITATION
ROOFS
STATION SITE
COAL PILE
ASH DISPOSAL SITES
ROOF DRAINS
YARD DRAINS
COAL PILE RUN-OFF
ASH PILE RUN-OFF (if required)
SEDIMENTATION LAGOONS
FLOCULATION/ CLARIFIERS
(see note 3)
LAGOONS FOR RE-USE OR DISCHARGE
NOTE 1: A secondary heat exchanger and recirculating cooling loop, is shown.
NOTE 2: An alternative recirculating evaporative cooling is shown. Once-through cooling is more probable, as shown.
NOTE 3: Flow equalization before all treatment processes and recirculation capability after all treatments (not shown)
NOTE 4: Seepage control used for coal piles, ash and sludge disposal sites. Minimized seepage not shown.
S SAMPLING AND FLOW MONITORING
S GROUNDWATER SAMPLERS
SEEPAGE CONTROL BARRIER
D DISCHARGE
A A Indicates continuation from a source to a point of discharge

FIGURE E.63 POSSIBLE WATER AND WASTEWATER SYSTEM SCHEMATIC FOR A COAL-FIRED STATION


WATER TYPE
PROCESSES
POSSIBLE WASTEWATER PRACTICES
OFFSHORE INTAKE
MAIN COOLING WATER
AUXILIARY COOLING WATER
CONDENSERS
HEAT EXCHANGERS (see note 1)
MODERATOR
USED FUEL
OTHER COOLING
RECIRCULATED COOLING WATER (see note 2)
COOLING TOWERS/PONDS
BLOWDOWN
TREATMENT (if required)
OFFSHORE OUTFALL
TO SURFACE WATERS (TYPICAL)
REACTOR/ SERVICE BUILDINGS
TURBINE/ OTHER BUILDINGS
STEAM GENERATORS
ACTIVE LIQUID TANKS (see note 3)
ACTIVE LIQUID WASTE TREATMENT SYSTEMS
(see notes 6&4)
SOLID WASTES
HOLDING TANK
FLOOR & EQUIPMENT DRAINS
OIL SEPARATORS
RAW WATER
FROM AUXILIARY COOLING DISCHARGE
PRETREAT
DEMINERALIZERS
BLOWDOWN
HOLDING TANK
REGENERATION WASTES
SLUDGE/BACKWASH
NEUTRALIZATION, SEDIMENTATION (see note 4)
SLUDGES
STABLE WASTES
WASHROOMS
LAUNDRY (COTTON)
SANITARY WASTES
SEWAGE TREATMENT
HEAVY WATER RE-USE (UPGRADED OR DETRITIATED)
HEAVY WATER MAKEUP
PRIMARY HEAT TRANSPORT
MODERATOR
LEAKS
LEAKS
LIGHT WATER
HEAVY WATER UPGRADER
HEAVY WATER UPGRADER
TRITIUM REMOVAL
LIGHT WATER
PRECIPITATION
ROOFS
STATION SITE
SOLID RADIOACTIVE WASTE STORAGE SITE (see note 5, typical)
SEDIMENTATION LAGOONS
HOLDING PONDS
HOLDING LAGOONS FOR RE-USE OR DISCHARGE (INCLUDES OIL BOOMS)
A B C D E F G H J K S
S SAMPLING AND FLOW MONITORING
S GROUNDWATER SAMPLERS
SEEPAGE CONTROL BARRIER
D DISCHARGE
A A Indicates continuation from a source to a point of discharge

NOTE 1: A secondary heat exchanger and recirculating cooling loop, is shown.

NOTE 2: An alternative recirculating evaporative cooling is shown. Once-through cooling is more probable, as shown.

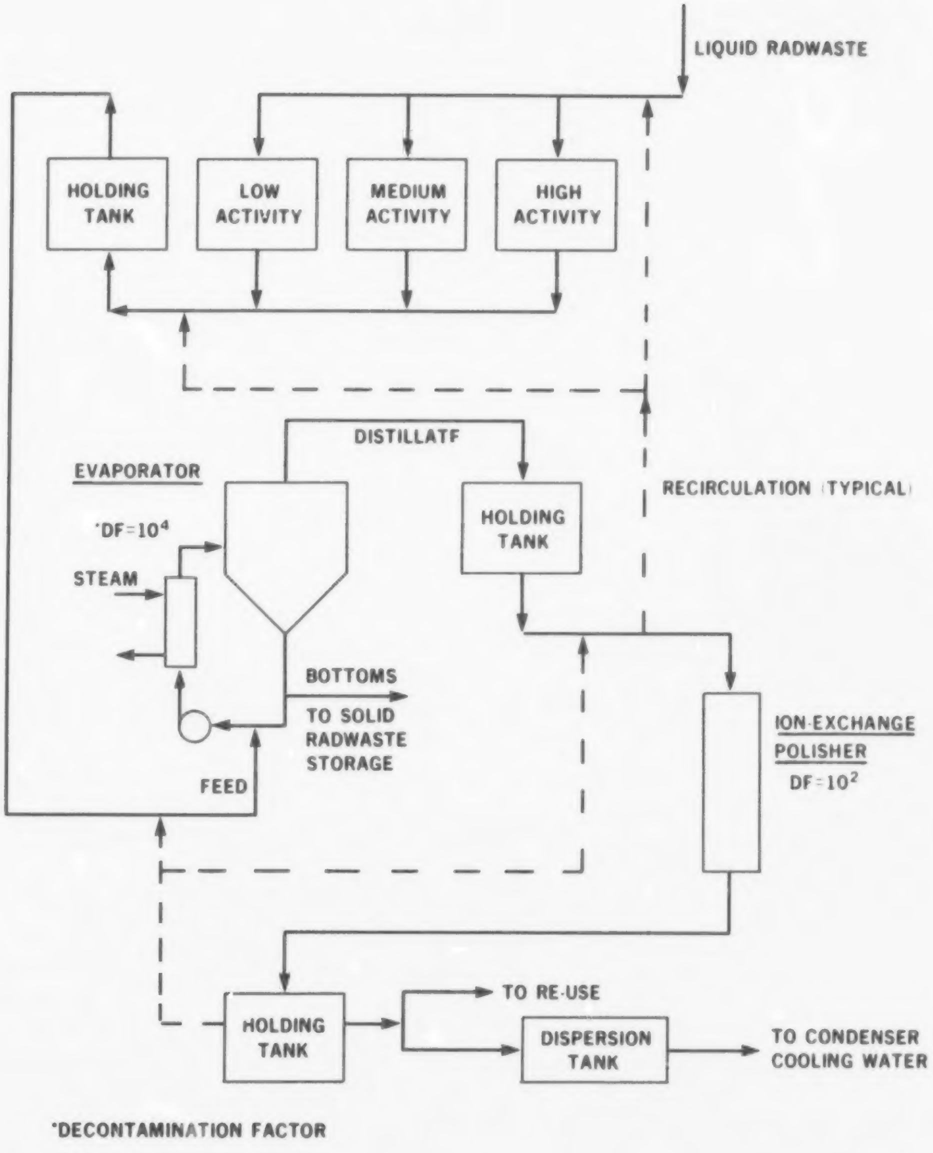
NOTE 3: (D) Wastes to active liquid tanks also include wastes from
- Decontamination centre
- Plastics laundry
- Fuelling machine shop
- Ion exchange slurry water
- Laboratories (high & low activities)
- Emergency showers, etc.

NOTE 4: Flow equalization before all treatment processes and recirculation capability after all treatments (not shown).

NOTE 5: Minimized seepage not shown

NOTE 6: Evaporation/bitumization could be used

FIGURE E.64 POSSIBLE WATER AND WASTEWATER SCHEMATIC FOR A CANDU STATION


LIQUID RADWASTE
HOLDING TANK
LOW ACTIVITY
MEDIUM ACTIVITY
HIGH ACTIVITY
DISTILLATF
EVAPORATOR
*DF=10⁴
STEAM
HOLDING TANK
RECIRCULATION (TYPICAL)
BOTTOMS
TO SOLID RADWASTE STORAGE
FEED
ION-EXCHANGE POLISHER
DF=10²
HOLDING TANK
TO RE-USE
DISPERSION TANK
TO CONDENSER COOLING WATER

*DECONTAMINATION FACTOR

FIGURE E.65 EVAPORATOR/ION EXCHANGER POLISHER TREATMENT SYSTEM FOR RADIOACTIVE WASTEWATERS

an event such as loss of coolant or decommissioning might also be removed and concentrated by a suitable TRS. However, the most common application of current tritium removal systems will be for tritiated moderator heavy water.

As indicated, the performance of various treatment systems depends on the wastewater characteristics and the treatment processes used. In order to assess the relative performance of the various systems discussed, a generic 1000-MWe CANDU station was considered (1). Various wastewater characteristics and process performances were derived, based on data reported in the literature and other sources. While a 1 000 MW(e) CANDU does not exist, this model is useful to assess the relative performance of various treatment systems.

The following assumptions are made (1):

i) Station Capacity 1 000 MWe

ii) Tritium release rates to water are expressed by the formula:

$T = V_p L_p C_p + V_m L_m C_m$

where: T = tritium release rate

V_p = volume of primary heat transport circuit (PHTC)

V_m = volume of moderator circuit (MC)

L_p = annual loss of PHT heavy water (fraction of total Vp)

L_m = annual loss of moderator heavy water (fraction of total Vm)

C_p = tritium concentration in PHTC

C_m = tritium concentration in MC

iii) The contributions to tritium releases from the PHTC and MC are both of the same order of magnitude. Although the tritium concentrations are higher in the MC, the leak rate is much lower than for the PHTC.

iv) The tritium concentrations in the PHTC and MC increase with operating time as shown in Figure E.66, without a tritium removal system.

v) The tritium removal system is designed to maintain the moderator tritium concentration at 130 GBq/kg and the primary heat transport at 19 GBq/kg, when steady state is reached.

Tritium release rates were estimated using the following input parameters in the above equation. The volumes Vp and Vm were prorated from data for a 2 000-MWe station.

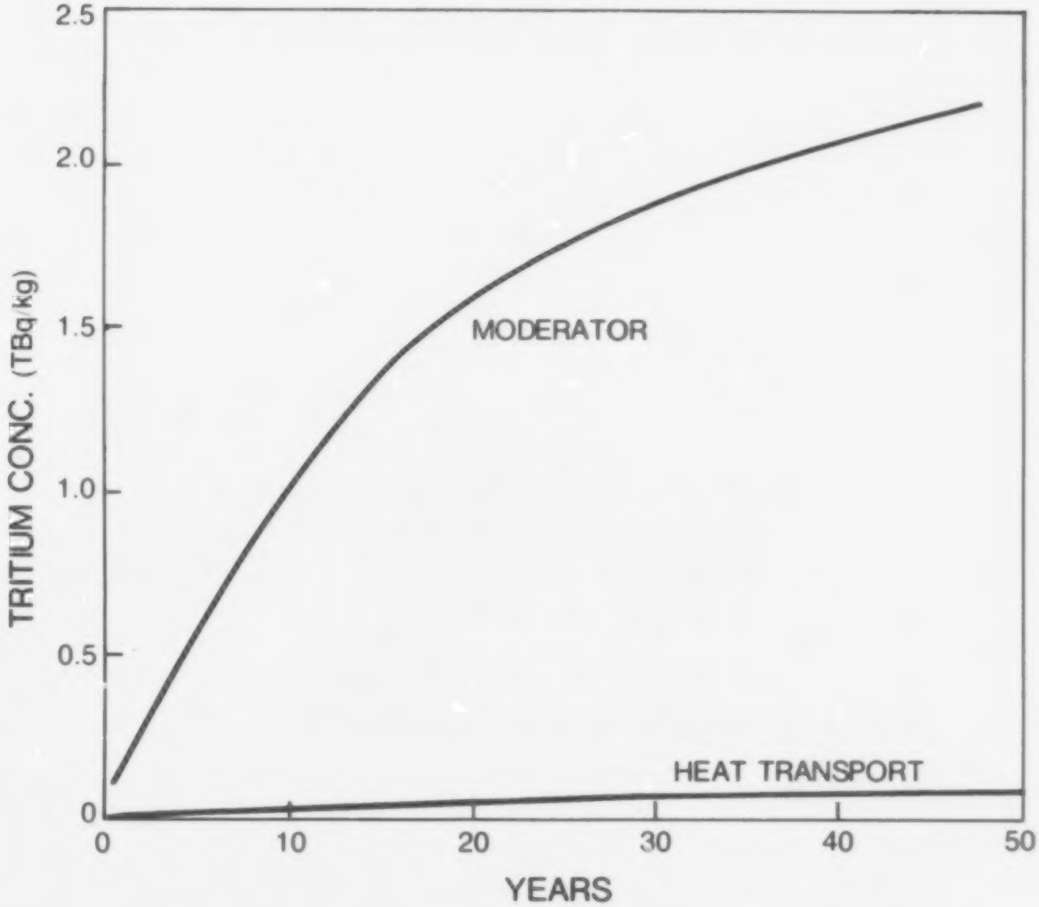


FIGURE E.66 TRITIUM BUILDUP IN CANDU HEAVY WATER SYSTEMS (1)

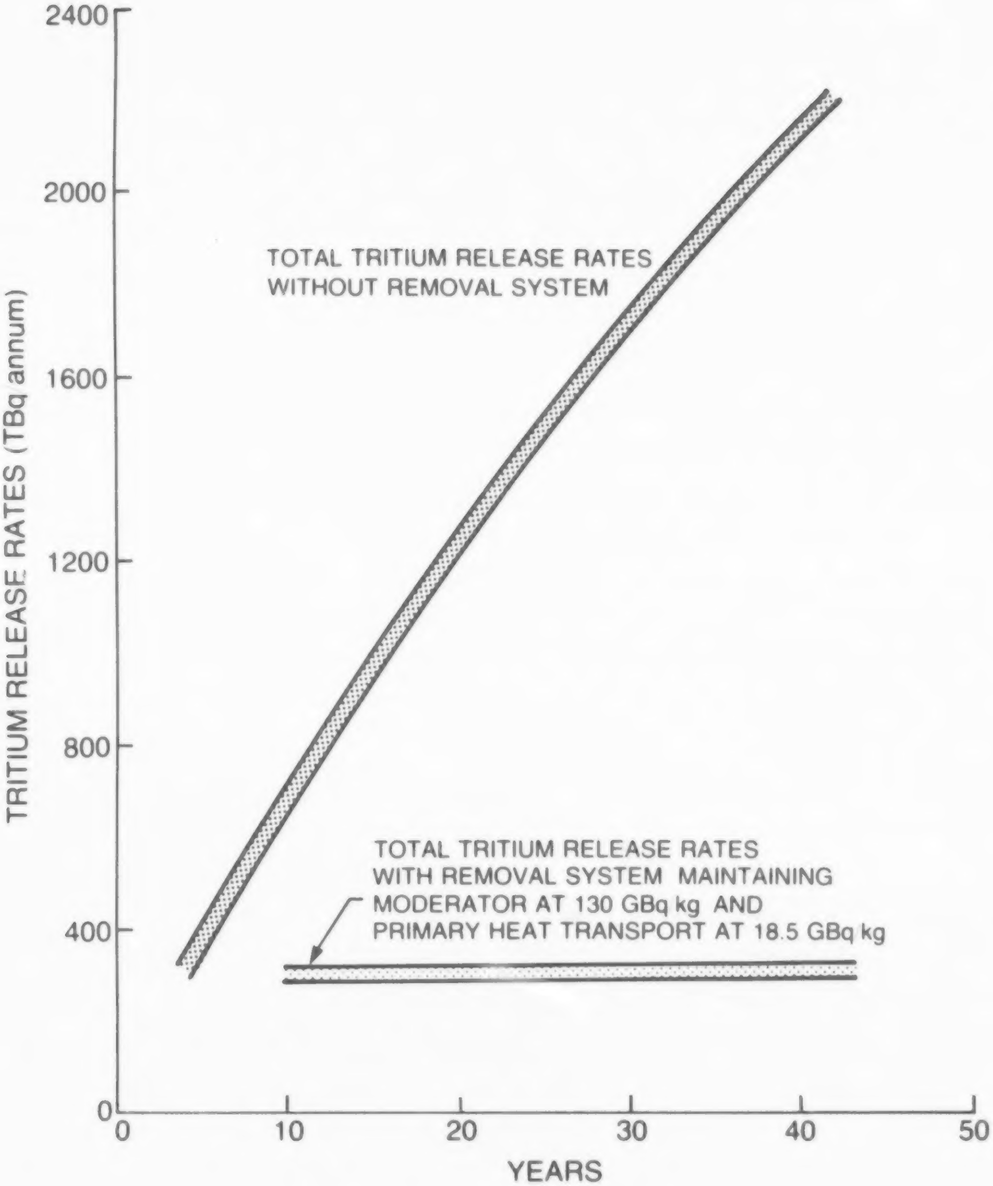
V_p = 340 000 L
V_m = 500 000 L
L_p = 0.04/annum
L_m = 0.0008/annum

The estimated tritium release rates calculated are shown in Figure E.67 for 40 years of plant operation. The release rates are very sensitive to the amount of heavy water losses, particularly from the moderator circuit. A family of curves could be generated for various assumed leak and spill rates. The curve shown in Figure E.67 agrees very well with actual release data (not shown) prorated to 1 000-MWe from operating 2 000-MWe and 3 000-MWe CANDU stations. A scatter of actual data for the 2 000-MWe station indicates the sensitivity of tritium releases to heavy water losses from the station.

The tritium removal efficiency of the cryogenic distillation system will be greatest when the higher tritium concentrations of the moderator coolant are fed to the system. However, tritium will also be removed at a lower efficiency when the primary heat transport heavy water is fed to the system. A tritium removal system is being designed in Ontario to maintain a steady state level of 130 GBq/kg in the moderator system and 19 GBq/kg in the heat transport system. These design levels were also assumed for the 1 000-MWe generic station considered. The maximum annual tritium release expected when a TRS is used is indicated in Figure E.67 (1).

From the foregoing, it is concluded that, for given rates of heavy water losses in the moderator and primary heat transport circuits, a tritium removal system will significantly reduce tritium releases from a CANDU station. For example, after 30 years of operation for a 1 000 MWe station, assuming certain losses of heavy water, a release of 1480 TBq/annum could be expected without a tritium removal system, whereas 370 TBq/annum could be expected with a tritium removal system. An annual release rate below 0.3 TBq/a•MWe is achievable with a tritium removal system and other design provisions (e.g., R203) throughout the life of a CANDU station. As indicated in Figure E.67 the effectiveness of a TRS increases with the age of the station.

To allow for operational upsets in the station and with the TRS, a maximum annual release rate of 0.5 TBq/a•MWe is assessed to be readily achievable with current technology. It is recognized that this release rate limitation could be achieved in a mature station by reducing leak rate rather than by using a TRS for the heavy water (See E.5.6, R212).



NOTES: i) ASSUMED MODERATOR ANNUAL LEAK RATE = 0.08%
ASSUMED PRIMARY HEAT TRANSPORT LEAK RATE = 4.0%

ii) ASSUMED MODERATOR AND PRIMARY HEAT TRANSPORT TRITIUM CONCENTRATIONS SHOWN IN FIGURE E.66

FIGURE E.67 ESTIMATED TRITIUM RELEASE RATES FROM A 1000-MWe CANDU WITH AND WITHOUT A TRITIUM REMOVAL SYSTEM (1)

For radionuclides other than tritium, the following assumptions are made to estimate the performances of various radioactive wastewater treatment technologies at a generic CANDU 1 000-MW(e) station: (1).

i)	Station Capacity	1 000 MW(e)
ii)	Active Liquid Waste Volume	25 000 m^3/a
iii)	Activity Releases	37 GBq/a gross beta-gamma
iv)	Average activity	1500 Bq/L

The decontamination factors (DFs) for the various processes previously described depend on the radionuclides present in the wastewater and their amenability to the treatment process. To assess the relative performance of various processes, reported DFs were considered and the various "typical" values listed below were assumed for the wastewaters. The DFs are the ratios of the influent and effluent activities (not the ratio of the waste residue and the influent activities).

Filtration	10^1
Ion Exchange	10^2
Filtration/Ion Exchange	10^3
Reverse Osmosis	10^2
Evaporator	10^4
Reverse Osmosis/Evaporator	10^3
Evaporation/Ion Exchange	10^6

The expected effluent qualities estimated for the various treatment processes considered are shown in Figure E.68, based on treatment of some or all of the active liquid wastes. The Canadian drinking water radioactivity parameters, used for screening the activity of water samples, are also shown for reference.

It is assumed that the filtration/ion exchange system is operated so that effluent in excess of 370 kBq/L is not discharged. The reverse osmosis/evaporator combination uses the reverse osmosis as a pre-concentration step before the evaporator for volume reduction. It is assumed that the activity of the permeate (dilute phase) from the reverse osmosis, and the distillate from the evaporator is such that the overal DF of the system in terms of influent-effluent, is of the order of 10^3. For the evaporator/ion exchange polisher combination, a 10^4 DF, may be assumed for the evaporator and a further 10^2 DF assumed for the distillate, to give an overall DF of 10^6. These latter DFs were cited by an evaporator supplier as guaranteed performance factors for liquid waste

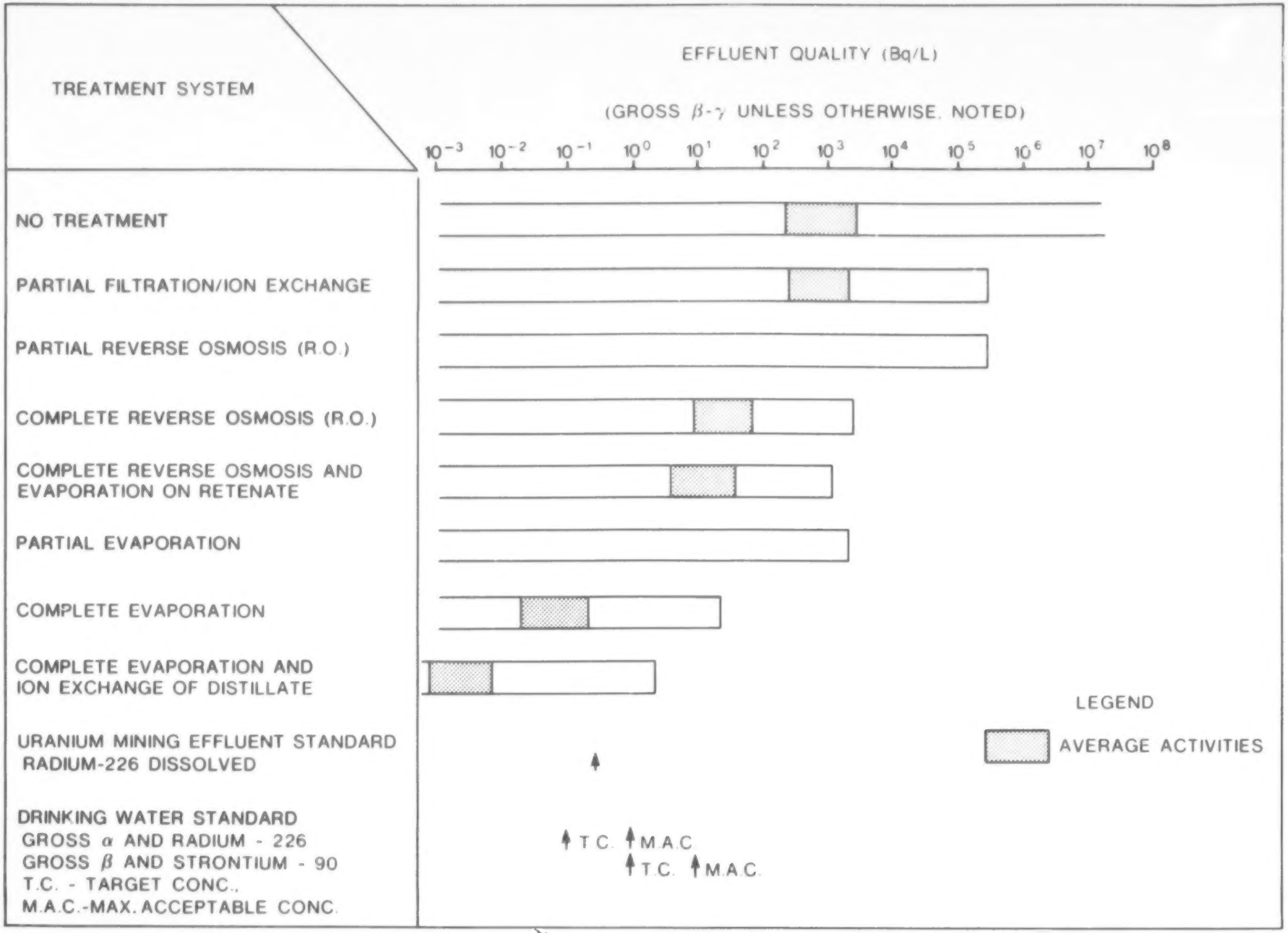


FIGURE E.68 EXPECTED EFFLUENT QUALITIES FOR VARIOUS RADIOACTIVE WASTEWATER TREATMENT SYSTEMS FOR CANDU STATIONS (1)

feeds with activities as low as 370 Bq/L (1). However, a DF less than 10^6 is assumed for Figure E.68. The efficiencies of physical and chemical treatment processes are highly dependent on influent characteristics and tend to decrease with influents of low suspended and dissolved solids (i.e., radioactivity). The removal of activities will depend on the operation of the system (e.g., treatment of some or all of the wastewater, recirculation of treated effluent for treatment again on a batch basis, etc.). Consequently, a wide range of possible effluent quality is indicated in Figure E.68. For the lower activity effluents, smaller DFs are assumed than for the higher activity effluents.

Figure E.68 indicates that increasingly low activity effluent can be produced from filtration/ion exchange, evaporators, reverse osmosis/evaporators and evaporators/ion exchange polishers, respectively. It can also be noted that an effluent quality comparable to the Canadian drinking water standard (in terms of gross activity) can be achieved with an evaporation/ion exchange polisher system and possibly with the other systems considered. This means essentially "zero discharge" of non-volatile man-made radionuclides from the station. Reductions in the activities of the untreated wastewater range from about 370 kBq/L to 3.7×10^{-3} Bq/L with the various alternative systems. It is concluded that an effluent quality of less than 1 Bq/L gross beta can be achieved, and that for a wastewater production rate of 25 m^3/a•MWe, this represents less than 25 000 Bq/a•MWe (25 kBq/a•MWe) (1).

However, to allow for operational upsets in the station and with an advanced radioactive wastewater treatment system, it is concluded that an effluent quality of less than 100 Bq/L gross beta activity is readily achievable with a number of current technologies. (See E.5.6, R212).

A brief assessment of the advantages and disadvantages of the various radioactive waste treatment technologies is outlined below:

i) Filtration/Ion Exchange - Low capital cost; high operating cost due to large volume of residue waste (spent filter cartridges and ion exchange resins); widely used technique.

ii) Reverse Osmosis - Medium capital cost; medium operating cost; may require pretreatment or cleaning to prevent plugging/fouling/failure of membranes; currently in development/demonstration phase for active liquid waste volume reduction.

iii) Evaporation - High capital cost; medium operating cost (high energy cost but low waste residue costs); provides a high decontaminaton factor for a wide variety of wastewaters; care should be taken with selection of materials of construction and foaming (laundry waste) liquids; widely used technique.

E.5.5 Prescribed Effluent Limitations. Treatment technologies are available to reduce many of the contaminants of environmental concern in power plant wastewaters. Of course, if water and wastewater systems are designed so that no process wastewaters are released from the generating station (i.e., "zero discharge"), the concerns associated with wastewater discharges no longer exist. However, the cost and operational implications of zero discharge do not warrant this strategy in most cases, in Canada.

The most common treatment technologies are oil removal and chemical neutralization. Various wastewater oil removal techniques will produce an effluent with less than 15 mg/L oil and grease (see Section E.5.2c). The segregation, collection and containment of potentially oily wastes at their source will minimize oil and grease discharges from a power station. Chemical neutralization is effective for the removal of many heavy metals. Treatability tests on various power plant wastewater streams show that concentrations of chromium, copper, nickel and zinc can be reduced to less than 0.5 mg/L and that iron can be reduced to less than 1.0 mg/L (see Section E.5.2d, E.5.3a,b). Hexavalent chromium can be reduced to less than 0.05 mg/L (see Section E.5.3 d).

Suspended solids can be readily reduced to less than 25 mg/L by filtration or may be reduced by other techniques such as sedimentation, skimming or cyclones (see Section E.5.2f). Total residual chlorine (TRC) can be reduced to less than 0.2 mg/L in blowdown from evaporative cooling recirculation systems. This can be accomplished by a chlorine minimization program or by a de-chlorination system (see Section D.5.3.a)

If wastewater management strategies are implemented at new or expanded stations to reduce selected heavy metals, chlorine and total suspended solids to certain effluent limits,then other contaminants of environmental concern may also be minimized. However, technologies are available to further reduce these other contaminants if they are of site-specific environmental concern.

Although technology-based effluent criteria specify concentration levels of certain contaminants, the intent of the Design Phase Code is that reasonable and practical measures be taken to minimize the total amount of contaminants discharged to the receiving environment. This precludes the dilution of concentrated wastewaters with once-through cooling water (Type 1 streams) as a "treatment" method. It also precludes the intentional dilution of highly concentrated wastewaters with high quality wastewaters that require minimal or no treatment to meet the effluent criteria. For example, general yard drains that might only warrant sedimentation and oil retention facilities should not be used to dilute metal cleaning wastes. However, wastewaters can be combined if it is shown that this combinaton results in chemical treatment. For example, in water treatment plants, acidic regeneration wastes from cation exchangers can be combined with alkaline regeneration wastes from anion exchangers. They will tend to neutralize each other. In some cases, alkaline wastewater from recirculating bottom ash systems may be used to neutralize mildly acidic wastes. However, it is expected that highly toxic metal cleaning wastes would warrant separate batch treatments with appropriate chemicals. Generally, the segregation of similar wastes is encouraged so that appropriate treatment or handling can be carried out. For example, roof drains and building perimeter drains might only warrant sedimentation, and these streams should be kept separate from a treatment plant designed to handle another type of wastewater, such as coal pile runoff.

Although it is the intent of the Design Phase Code to minimize the total releases of contaminants from steam electric stations, it is not practical to formulate a recommendation for total quantities released for fossil-fuelled stations. The regional differences in precipitation and the differences in the designs of water management systems are too great.

RECOMMENDATION R211. For all wastewater (Type 2 water) streams from steam electric generating stations, the following effluent quality criteria should be met before release to the once-through cooling water, a municipal sewer or directly to local receiving waters:

Parameters and Elements	*Recommended Effluent Quality*
pH	*6.5 to 9.5*
Iron	*$\leq$1.0 mg/L*
Chromium (hexavalent)	*$\leq$0.05 mg/L*
Chromium (total)	*$\leq$0.5 mg/L*
Copper	*$\leq$0.5 mg/L*
Nickel	*$\leq$0.5 mg/L*
Zinc	*$\leq$0.5 mg/L*
Total Suspended Solids (TSS)	*$\leq$25.0 mg/L*
Oil and Grease	*$\leq$15.0 mg/L*
Total Residual Chlorine (TRC)	*$\leq$0.2 mg/L*

Note:

1) Metal concentrations are for total dissolved and undissolved solids.

2) Values apply to average weekly composite samples.

E.5.6 Radioactive Wastewater Management. As discussed in Section E.5.2 i), l) and m), E.5.3 e), and E.5.4 c), a number of technologies and practices are available for the control of radionuclide discharges from nuclear stations to once-through cooling systems and receiving waters. The expected performances of many of these technologies have been described in Section E.5.4 c).

Reductions in radionuclide discharges will reduce ionizing radiation doses to the public and may decrease or increase doses to workers at the nuclear stations. While order of magnitude costs of applying some radioactive waste management technologies have been estimated in Appendix G of the Design Phase Code, changes in radiation doses resulting from the application of these practices have not been assessed in this document. Such an assessment is outside the scope of the Design Phase Code, but may be the subject of future studies.

However, it is evident that a number of technologies and practices are available for the elimination or further control of man-made radionuclides from nuclear stations and for the resulting preservation of the aquatic environmental quality.

RECOMMENDATION R212. Technological opportunities should be considered for the further control of radionuclide discharges from nuclear-powered steam electric generating stations.

E.5.7 Sanitary Wastewater Treatment. As discussed in Section E.5.2, a number of biological treatment systems can be applied to sanitary wastewaters from generating stations. Commercially available "packaged" sewage treatment plants are commonly used at generating stations which cannot discharge into municipal treatment systems. These are often sized for the peak construction force population at the site, so that they are more than adequate for reliable secondary biological treatment for the smaller operating staff population.

Packaged sewage treatment plants are common at various federal installations such as armed forces bases and national parks. The guidelines for effluent quality and wastewater treatment at federal installations are (161):

Biochemical Oxygen Demand (BOD_5)	20 mg/L
Suspended Solids	25 mg/L

This represents effective secondary biological treatment for sanitary wastewaters, although 15 mg/L BOD_5 and 15 mg/L suspended solids have also been formulated as secondary effluent objectives (162). Various available "secondary" treatment systems will result in different effluent qualities.

RECOMMENDATION R213. Sanitary wastewaters in steam electric generating stations should:

i) ***be kept separate from other station wastewaters;***

ii) ***be given secondary biological treatment when not directed to a municipal sewage treatment plant.***

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APPENDIX F

RATIONALE FOR RECOMMENDATIONS - MONITORING

APPENDIX F

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APPENDIX F RATIONALE FOR RECOMMENDATIONS ON MONITORING

F.1 General

The recommendations in the foregoing sections, and sound environmental practice generally, require that an effective monitoring program be established at all new and expanded steam electric generating stations. A recommended comprehensive monitoring program will be contained in the Environmental Code of Practice, Operations Phase, scheduled for completion in 1986. For reference in the following discussion on station design features needed to accommodate a thorough monitoring system, tentative monitoring programs for the Operations Phase Code are discussed in Section F.7. These programs will be refined in the Operations Phase Code but are adequate in their present form to aid in examining plant design features and equipment that will facilitate monitoring.

Effective monitoring at steam electric stations is required for several purposes. Among these are:

- to quantify the contaminants being released to the environment;
- to verify that the actual wastewaters generated have flows and characteristics similar to those estimated for designing minimization, containment and treatment systems;
- to enable assessment of the performance of wastewater minimization, containment and treatment systems;
- to provide adequate data on actual wastewater flows and characteristics to enable the reasons for poor performance of wastewater minimization, containment and treatment systems to be identified and appropriate corrective action to be determined;
- to enable assessment of the performance of devices being used to control the behaviour of and/or minimize damage to aquatic organisms subject to potential impingement and entrainment in various components of cooling systems; and
- to establish the effects in the receiving environment (both surface water and ground-water) of the operation of the plant and the adequacy of the environmental protection measures being employed.

Facilities and design features that will enable a monitoring program with these objectives to be effectively implemented are discussed and recommendations are made in the following sections regarding provision of appropriate facilities and accessibility at new and expanded generating stations.

A general consideration which applies to all monitoring is the safe access and appropriate location of monitoring facilities. Past experience has shown that, at most existing generating stations, monitoring is difficult because appropriate sampling locations cannot be accessed safely (or cannot be accessed at all) during normal plant operation. Safe access to sampling locations can generally be provided with little expense or difficulty during the design phase. Safe access considerations include:

i) tripping, falling, or obstacle avoidance;
ii) proximity to moving equipment;
iii) confined spaces;
iv) hazardous fumes, dust or other materials;
v) oxygen depletion;
vi) deep or swiftly flowing water;
vii) heat;
viii) fire hazard, and the possibility of sampling equipment acting as an ignition source;
ix) electrical hazards.

In addition, particular attention should be given to the design of sampling equipment itself where high pressure streams or hazardous substances are involved.

The location of sampling equipment should take into account:

i) routine operation and sample collection;
ii) storage of samples - the volumes may in some cases be large;
iii) routine maintenance and access for maintenance equipment;
iv) provision of services (electric power, water for cleaning equipment).

RECOMMENDATION R301. Safe access and appropriate locations should be provided for all flow monitors, on-line instrument monitors and sampling facilities selected for environmental monitoring.

F.2 Once-Through Cooling Water

F.2.1 Equipment and Facilities

(a) Flow and Volume Measurements. A variety of devices for flow measurement are discussed in Section F.3.1. However, in once-through cooling water systems the determination of flow from pump discharge pressure and data supplied by the pump manufacturer may be an acceptable and inexpensive alternative to specialized flow measuring devices. Continous flow measurement can be accomplished by continuous recording of pump discharge pressure. To compensate for inherent inaccuracies of the method such as the change in flow with impeller wear, flow can be verified from time to time by methods such as tracer dilution studies. Facilities required for doing this, in addition to normal sampling facilities, are points where tracer can be injected, ideally in an area where mixing is assured such as the suction of a centrifugal pump.

(b) Temperature Measurements. Temperature sensing equipment is in common use at steam electric power generating stations. For environmental monitoring, temperatures would normally be monitored and recorded continuously.

(c) Chemical Additive Measurements. The main chemical additive of concern in once-through cooling water systems is usually chlorine. Effective monitoring of total residual chlorine (TRC) requires continuous chlorine residual analysis at the outlet of each condenser during the chlorination period. Reliable equipment to do this is available and consists of an amperometric continuous analyzing cell and a recording mechanism (1,2). This system may be integrated into a closed loop TRC control system as described in section D.5.3.

Chemical additives other than chlorine, such as those which inhibit scaling and corrosion, are normally monitored by laboratory analysis of cooling water samples. Samples are either of the discrete or composite type. Generally, composite samples provide more useful information but may be associated with more complex equipment. Discrete samples may be desirable for once-through cooling systems, however, and the equipment, which may consist of a small manually operated valve on a pressurized line, is simple and inexpensive. It may be appropriate to install equipment capable of obtaining both types of samples in once-through cooling systems. A discussion of types and applications of samples and sampling equipment is provided in section F.3.1.

(d) Aquatic Organism Sampling. This type of sampling generally does not require permanently installed equipment. It is discussed in the following section on location and accessibility.

F.2.2 Location and Accessibility. The purpose of monitoring once-through cooling water is to verify that the once-through cooling (series 100) recommendations are being met and to identify the effects of this water on the environment. A system of monitoring locations that would fulfill this function is shown in generalized schematic form in Figure F.1. The exact location of monitoring equipment will be determined by piping layout,

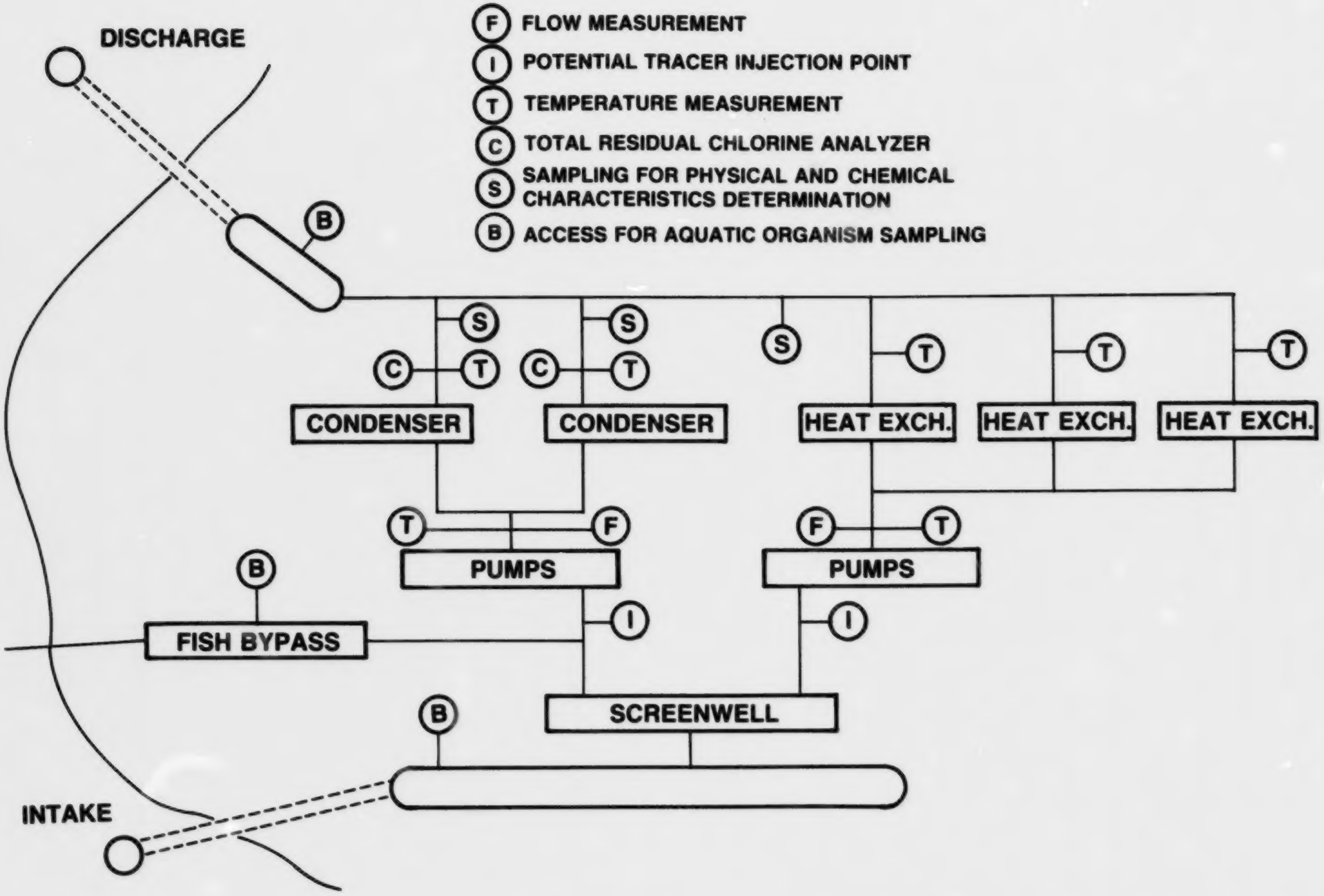

F FLOW MEASUREMENT
I POTENTIAL TRACER INJECTION POINT
T TEMPERATURE MEASUREMENT
C TOTAL RESIDUAL CHLORINE ANALYZER
S SAMPLING FOR PHYSICAL AND CHEMICAL CHARACTERISTICS DETERMINATION
B ACCESS FOR AQUATIC ORGANISM SAMPLING
DISCHARGE
B
S
C
T
S
C
T
S
T
T
T
CONDENSER
CONDENSER
HEAT EXCH.
HEAT EXCH.
HEAT EXCH.
T
F
F
T
B
PUMPS
PUMPS
I
I
FISH BYPASS
B
SCREENWELL
INTAKE

FIGURE F.1 SCHEMATIC DIAGRAM OF MONITORING LOCATIONS FOR ONCE-THROUGH COOLING SYSTEMS

characteristics of the equipment and the need for access for routine sample collection and maintenance.

If tracer methods are to be used to verify cooling water flows, access must be provided for injection of tracer. Ideally this would be at the suction of the condenser cooling water pumps but alternative locations include the pump discharge or a point upstream of a flow control valve or other device that would create turbulence and ensure mixing.

As described in section D.4.2 aquatic organism mortality may be higher in auxiliary cooling systems than in condenser cooling. Therefore in assessing aquatic organism mortality in the once-through cooling system, it will be advantageous to determine flow separately for condenser and auxiliary cooling systems.

Temperature differences across condensers and heat exchangers have a major influence on aquatic organism mortality. Generally the temperature at the inlet of condensers and heat exchangers will be very close to that of the intake water and this can be monitored at one convenient location. Temperature monitoring at the outlet of each condenser and heat exchanger will allow temperature differences to be calculated. Such a temperature monitoring system would be greatly simplified if auxiliary coolers were of the intermediate recirculating loop type specified in recommendation R203. Such a system would commonly consist of relatively few secondary heat exchangers each serving many primary heat exchangers. For environmental purposes, temperature monitoring would be done only on the secondary heat exchangers.

To be consistent with recommendation R111 the residual chlorine analyzer should be at the condenser outlet. If dechlorination is practiced, however, the chlorine analyzer must be far enough downstream of the dechlorination equipment, normally immediately at the condenser outlet, to allow time for mixing and reaction prior to chlorine analysis. Under ideal conditions, mixing will be complete within 10 pipe diameters and the minimum time for the dechlorination reaction (using SO_2) to go to completion will be 30 seconds (1).

In systems where scaling and corrosion control chemicals are added independently to each condenser a program of chemical minimization will require sampling facilities at the outlet of each condenser. In the auxiliary cooling system this level of detail will probably not be warranted. If auxiliary cooling streams come together at a point prior to joining the condenser cooling discharge, this would be a suitable point for sampling.

Aquatic organism sampling will require access to the cooling water forebay and discharge areas and to the fish bypass facilities. Aquatic organism sampling normally will be done using nets. It will be advantageous to cover the entire cross section of the intake or discharge area with nets to get a representative sample of free swimming fish species capable of avoiding nets. For offshore submerged discharges this type of sampling would be facilitated by an open channel section of the discharge prior to the entrance to the discharge tunnel.

RECOMMENDATION R302. For once-through cooling systems, provisions should be made for:

(i) ***routine flow monitoring of condenser and auxiliary cooling water;***
(ii) ***routine temperature monitoring of water intake, individual condenser discharge and auxiliary heat exchanger discharges;***
(iii) ***continuous total residual chlorine (TRC) monitoring at condenser and heat exchanger discharges if chlorine is used;***
(iv) ***grab sampling at individual condenser discharge and auxiliary cooling system discharge.***

RECOMMENDATION R303. For once-through cooling systems, provisions should be made for periodic biological sampling of the:

i) ***cooling water forebay;***
ii) ***cooling water discharge; and***
iii) ***fish bypass system.***

F.3 Wastewaters

F.3.1 Equipment and Facilities

(a) Flow and Volume Measurements. A variety of equipment is available for monitoring wastewater flows. Factors affecting the choice of equipment will include wastewater characteristics such as solids and oil content, conductivity, cost, maintenance requirements, accuracy and application. The three applications discussed in this section are continuous closed channel and open channel flow monitoring, and non routine flow monitoring. More detailed information concerning closed and open channel flow monitoring is available in the literature (3,4,5).

The most common closed channel flow measurement devices use pressure drop (orifice and venturi meters), electro-magnetic induction (magmeters), point velocity (pitot tube or annubar meters), current velocity (turbine meters), positive displacement (run time meters on positive displacement pumps), or sound velocity differential (sonic meters) to determine flow. An assessment of the applicability of these devices to a fossil-fuelled power station is summarized in Table F.1 (6). A variety of devices are available which can measure flow with an accuracy much better than ± 10 percent (6,7). The use of centrifugal pumps (pump capacity vs. discharge head data) for flow determination can lead to significant inaccuracies because of the effects of impeller wear, variation in suction or discharge head and pump characteristics. However pumps can be periodically calibrated by techniques such as tracer injection as discussed in section F.2.1 (a), or by measuring the pumping time required to empty a sump or vessel. The discharge pressure of a pump can be continuously monitored and the flow calculated from the pump characteristic curve.

Two common facilities for measuring flow in an open channel are weirs and flumes. Flow measuring weirs have the advantages of low cost, reliability, and reasonable accuracy (5-10%) (5,6). Disadvantages include upstream accumulation of solids and a limited operational range. The velocity of approach to the weir should be negligible and this may require special design features in the flow channel. Flow over a weir is proportional to the discharge head over the weir, usually measured by a liquid level sensor and chart recorder located upstream of the weir. As illustrated in Figure F.2 (5) the liquid level sensor should be located a specified minimum distance from the weir to avoid errors due to the drawdown effect at the weir crest.

Flow measuring flumes are commonly applied flow measuring devices which operate using the Venturi principle to determine flows, i.e., if downstream flow conditions do not affect the flow through the flume, then a definite relationship exists between the upstream liquid depth and the flow through the facility. Flumes have the same reliability and accuracy as weirs, but offer the advantages of being self-scouring and having minimal effects on upstream hydraulic characteristics. Flumes, however, are considerably more expensive than weirs.

Three commonly used types of flumes are the Parshall, Leopold Lagco, and Trapezoidal flumes. A Parshall flume is illustrated in Figure F.3 (5). Flow is measured by a liquid level sensor which is located at a point exactly defined for each type of flume.

Another method of determining flow in open channels uses the Manning equation to relate depth of liquid in an open channel to flow. This method is not discussed further because innaccuracies of 10-25% make it inferior to other methods (5,8).

Liquid level measuring instruments may use buoyant objects, gas pressure in a dip tube, or sonic effects to sense liquid level in a weir or flume. The choice of

TABLE F.1 CORONADO GENERATING STATION FLOWMETER COMPARISON TABLE (6)

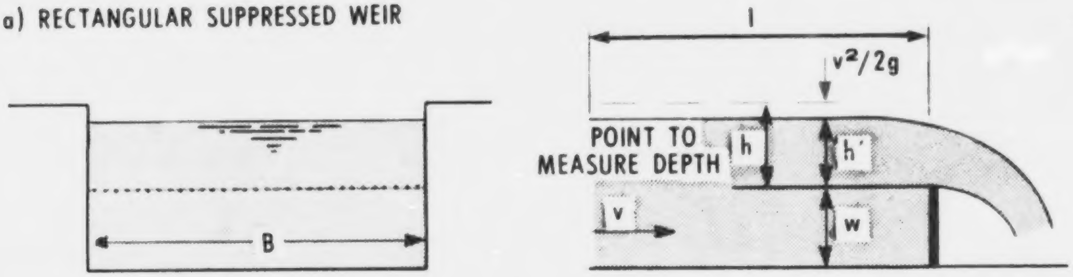
Type	Quantity (2 UNITS)	Description of Service	Operating Conditions	Range-ability	Accur-acy	Percent Relative Cost	Relative Perfor-mance	Remarks
Variable Head								
Orifice	2	Zeolite softened water to Evaporator	120C,1380 kPa	4:1	±5	Moderate	Good	Rangeability Low
Venturi	2	Evaporator Blowdown - Brine, High TDS	120C,	4:1	±5	High	Good	Rangeability Low
Annular Averaging (Annu Bar)	9	Deep well raw water - High TDS., Entrained Air Intermittent Sand	16C,690 kPa	4:1	±10	Low	Poor	Some Velocity heads are too low Entrained air is problem
	2	Circ. water make up-softened water, low TDS	16C,170 kPa					Rangeability low
Positive Displacement								
Nutating Disk	1	Zeolite Regen.-Brine High TDS	16C,340 kPa	20:1	±0.1-0.5	Moderate	Good	Filter Clogs
Run Time Meters	2	Oily waste pumps - Water & Oil Mix	N/A	N/A	±0.5	Low	Excellent	Indirect measure based on design flow of PD pump
	4	Sump pumps - water & Oil Mix	N/A					
	2	Water Softener Sludge Pumps - C_aCO_3 Sludge	N/A					
Volumetric								
Turbine	10	Deep Well Water - High TDS	16C,690 kPa	10 to 1	±0.5 of rate	Low	Excellent	Rangeability could cause problems, requires periodic maintenance
	9+1[a]	Softened water - station service	16C,690 kPa					
	1	Portable water - soft sater - chlorinated	16C,690 kPa					
	1	Demineralizer inlet - soft water	16C,690 kPa					
	1	Demineralizer outlet - Condensate	16C,550 kPa					
	3	Zeolite softener inlet - soft water	16C,690 kPa					
	1	Recoverable water - separated oily waste	38C,140 kPa					
	2	Cooling water - condensate	38C,380 kPa					

TABLE F.1 CORONADO GENERATING STATION FLOWMETER COMPARISON TABLE (6) (Cont'd)

Type	Quantity (2 UNITS)	Description of Service	Operating Conditions	Range-ability	Accur-acy	Percent Relative Cost	Relative Perfor-mance	Remarks
Vortex Velocity	1	Pressure Filter Backwash	16C,690 kPa	5 to 1		High	Fair to Poor	Misapplied, out of range and expensive
	2	Zeolite softener regeneration/rinse[b]	16C,590 kPa					
	2	Demineralizer regeneration/rinsde[b]	16C,590 kPa					
	2	Chemical Feed area sumps	38C,117 kPa					
	2	Boiler Drum Blowdown	93C,138 kPa					
	2	Contaminated water	16C,300 kPa					
	2	Cooling tower blowdown[c]	16C,230 kPa					
	4	Cooling water makeup - condensate	16C,90 kPa					
Obstructionless								
Electromagnetic	1	SO_2 Scrubber Sludge	49C,620 kPa	20 to 1	±1	High	Excellent	Expensive, Piping requirements are minimal
Ultrasonic	2							
Beam Deflect	1	Yard sump/ash area overflow	40C,165 kPa	20 to 1	±2	Moderate	Good	Pump discharge vibration problem
Transit Time	1	Contaminated water	16C,230 kPa	20 to 1	±2	Moderate	Excellent	Opaque flows not measurable
Open Channell								
Weir	1	Sewage Effluent	Atmospheric	10 to 1	±10	Low	Fair	Inaccurate
Flume	1	CT Blowdown water Res. overflow	Atmospheric	10 to 1	±10	Moderate	Fair	Sensitive to wave action

[a] Substituted a Propeller type with a Turboprobe
[b] To be replaced with Turbine Meters
[c] Changed to Turbine Meters

a) RECTANGULAR SUPPRESSED WEIR

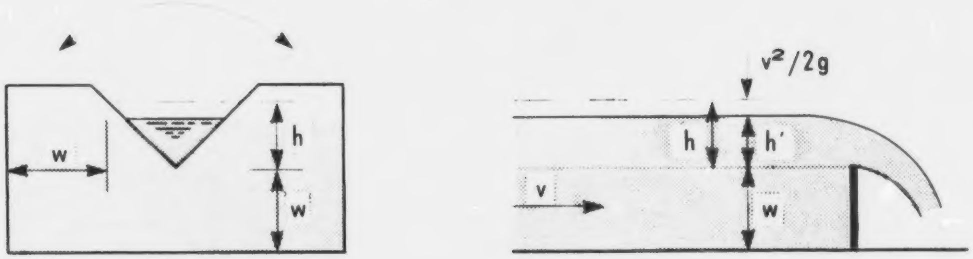

l
$v^2/2g$
POINT TO MEASURE DEPTH
h
h'
v
w
B

RECOMMENDED GEOMETRY: $w=2h_{max}$, $l=4h_{max}$

FLOW RATE: $Q(m^3/s/m)=2.953(0.604+.081h/w)(h+.001)^{1.5}$
WHERE h,w (m)

$Q(cfs/ft)=5.347(0.604+.081h/w)(h+.0034)^{1.5}$
WHERE h,w (ft)

b) 90° V-NOTCH WEIR


w
h
w
$v^2/2g$
h
h'
v
w

RECOMMENDED GEOMETRY: $w=2h_{max}$

FLOW RATE: $Q(m^3/s)=1.34h^{2.48}$ (m)

$Q(cfs)=2.48h^{2.48}$ (ft)

FIGURE F.2 RECTANGULAR AND V-NOTCH WEIRS (5)

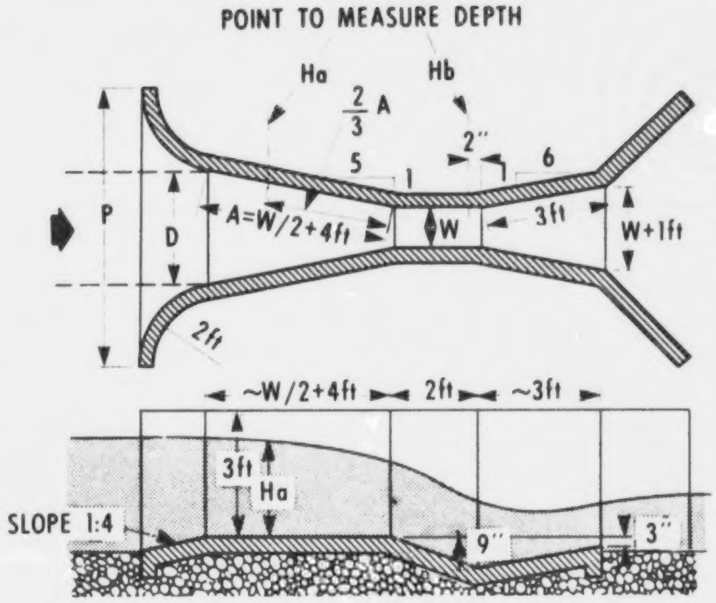


FIGURE F.3 TYPICAL PARSHALL FLUME (5)

instrument will be determined by required accuracy, cost, velocity of flow, and nature of the contaminants (i.e., suspended solids, fouling materials) in the fluid to be measured. The output signal of level sensors is usually converted into a flow proportional signal by electronic components or mechanical cams, and recorded on a chart recorder.

In applications where flow measurement will not be required on a routine basis, potential exists for using a less expensive method of determining flow. A pitot tube, shown in Figure F.4 (4), or annubar is a very simple device that can be inexpensively installed in a pipe. A portable differential pressure meter can be attached to the device when a flow measurement is needed. For abrasive service the pitot tube can be inserted into a port only when a flow measurement is required.

Tracer methods allow a highly accurate determination of flow at one point in time. Generally the method is limited to systems where flow is constant over a period of at least several minutes and where good mixing can be assured. The accuracy is essentially that at which the tracer can be analyzed. Tracer injection and recovery points must be separated by devices which ensure good mixing such as pumps or throttling valves or by sufficient lenth of pipe under turbulent flow conditions.

In some systems it may be possible to determine flow by measuring the length of time required for emptying a sump, tank or lagoon of known capacity.

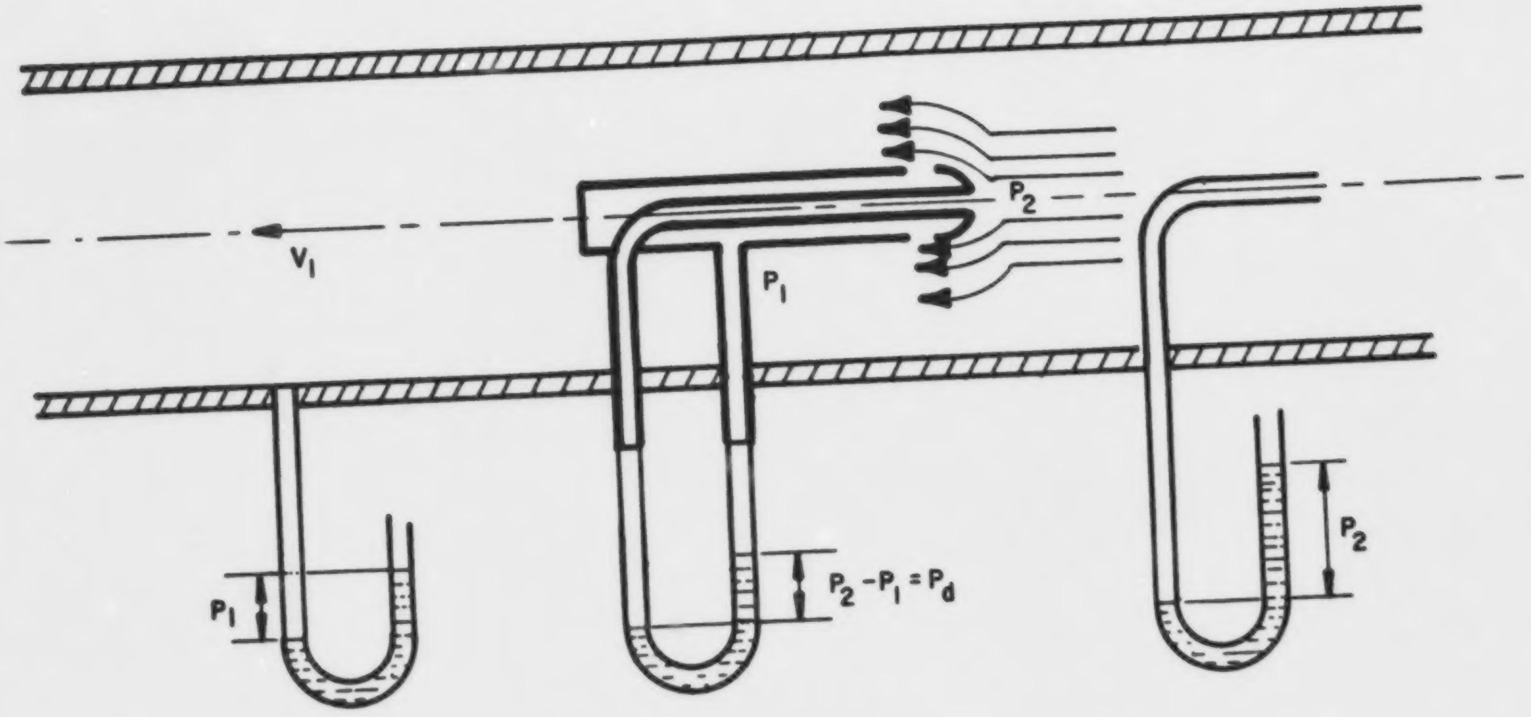

V_1
P_1
P_2
P_1
$P_2 - P_1 = P_d$
P_2

FIGURE F.4 PITOT TUBE MEASURES VELOCITY HEAD (4)

For all routine flow monitoring equipment some method of integrating instantaneous flow measurements to determine total flow over a time period is essential in calculating the total amount of contaminants discharged. Flow integration may readily be accomplished by graphical methods or by mechanical or electronic components.

(b) Sampling For Physical and Chemical Characteristic Determination. Sampling for physical and chemical characteristics determination may involve discrete or composite sampling. A discrete sample indicates the condition of a wastewater at one point in time only and cannot normally be used for estimation of the total discharge of a substance where the wastewater quality is variable.

Composite samples can be made up from a number of discrete samples or by the continuous withdrawal of sample from a wastewater. A sample composited over time allows a more accurate estimate of total discharge over a period of time but may obscure variations in concentration of a substance.

Generally the suitability of discrete or composite sampling techniques depends on the nature of the stream to be sampled, the information required and the practicality and cost of the technique. The objective of sampling is to represent as closely as possible the characteristics of the stream. For the purpose of this Code "representative" sampling may involve one discrete sample, a series of discrete samples, or a composite sample. For example, where the quality of a wastewater is relatively constant over a given time period, one discrete sample during that period would be adequate. Where the quality of the wastewater varies rapidly, a series of discrete samples would better represent the characteristics of the wastewater. However where the cost of analyzing a series of discrete samples was prohibitive a composite sample might be a reasonable alternative.

Both discrete and composite samples may be collected by manual or automatic means. Manual grab sampling is appropriate for obtaining a discrete sample. Facilities for grab sampling may be as simple as a manually operated tap on a pressurized line or a location on an open flow channel where a sample may be taken using a long handled scoop. Descriptions of commercial automatic samplers are available in the literature (4,5).

In selecting sampling equipment and facilities, suspended solids deserve special attention. To obtain representative samples material is taken from the centre of the channel of flow where velocity is highest and the possibility that solids have settled out is minimal. For sampling probes, the probe inlet is oriented parallel to the flow and, ideally, faces the flow (8). Intake line velocities of at least 1 m/s (or for vertical sections a velocity greater than the settling velocity of the densest particle) have been recommended to prevent settling in the line (5,9) but lower velocities have been used successfully (10).

Floating materials such as the lightweight cenospheres found in fly ash, and oil and grease create special sampling problems in streams which contain them. A representative sample for floating suspended solids or oil and grease determination can only be taken at a very well mixed point such as the discharge of a centrifugal pump. There is no practical means of obtaining a representative sample of a stream containing floating material in non-turbulent or open channel flow. Grab samples are usually used when such samples must be taken in open flow channels but the capture of floating material depends highly on the sampler's technique.

Materials of construction of the sampling equipment may alter the characteristics of the sample. Metals, oil and grease, and organic chemicals may be absorbed on glass, or polyetheylene sample lines or containers. Metals such as zinc, cadmium, or copper may be leached from sample lines or containers (8,9).

Composite samples are not suitable for monitoring of pH because they may obscure wide fluctuations. Where discrete samples are taken pH must be determined immediately because it may change as the sample stands. The most suitable method for monitoring pH is a probe immersed in the wastewater and attached to a continuous recorder. This is normally accomplished by monitoring pH in a side stream of the main flow. Fluid velocity and abrasion can be controlled to prolong probe life by valving and filters on the sidestream and the probe can easily be isolated for maintenance.

F.3.2 **Location and Accessibility.** To determine whether the criteria of R211 are being met it will be necessary to locate routine monitoring facilities on all wastewater streams discharging to once-through cooling water, a municipal sewer, or directly to local receiving waters. Variations in generating station design and operation, reuse of wastewater, and mixing of wastewaters for treatment will mean that monitoring facility location will be highly site specific. For guidance in determining monitoring facility location the reader is referred to section F.7, which outlines tentative Type 2 stream monitoring requirements being considered for the operations phase code. It is emphasized that generating station design will determine the Type 2 streams which are actually discharged and that this will in turn determine routine monitoring facility location.

As indicated in Section E.5.5 the intent of R211 is that the total discharge of contaminants to the receiving environment be minimized. The monitoring of flow at each sampling location will make it possible to calculate total discharges and will indicate those areas where improvements can be made.

In addition to routine sampling of wastewaters it may be desirable from time to time to gain information from other parts of the plant water system that affect the generation of wastewater. This information may include:

(i) raw water make up flow and quality;

(ii) pump seal flows;

(iii) process make up flows (e.g., wet ash transport, FGD, cooling tower or pond);

(iv) fire water, floor and equipment wash down flows, sump discharges, etc.;

(v) process blowdown/overflow flows and qualities (e.g., wet ash transport, cooling tower or pond);

(vi) periodic wastes volumes and qualities (e.g., boiler cleaning wastes, etc.); and

(vii) other wastewater flows and quality at points prior to convergence with other wastewater streams or prior to entrance into wastewater treatment facilities.

Access to these parts of the plant water system can generally be provided easily and at low cost during the design phase. Access to the water itself may take the form of sampling ports, ports through which flow monitoring equipment such as a pitot tube or annubar can be inserted, or pairs of injection and sampling parts which could be used for flow monitoring by tracer methods. No permanent monitoring equipment would be provided, but access would facilitate the identification of trouble spots relating to water use, and the measurement of waste treatment performance.

RECOMMENDATION R304. For wastewaters discharged under normal and emergency conditions to once-through cooling water, a municipal sewer, or directly to local receiving waters, provisions should be made for:

(i) representative sampling,

(ii) continuous monitoring and integration of flow rate or total volume discharged over time at an accuracy better than ± 10% of flow or volume, and

(iii) continuous on-line monitoring of pH, total residual chlorine and other appropriate parameters.

RECOMMENDATION R305. For raw water make up, in-plant process and service water, and wastewater streams prior to mixing with other streams, provisions should be considered for:

(i) non-routine sampling of the water streams, and

(ii) non-routine flow monitoring of water streams.

F.4 Seepage to Groundwater

The design and installation of facilities to monitor seepage to and contamination of groundwater will require site specific considerations and should be done by personnel qualified in hydrogeologic investigation. For detailed information concerning groundwater monitoring the reader should consult the references used in this report (11,12) or texts dealing with hydrogeology.

F.4.1 Equipment and Facilities

(a) Level and Flow Measurements. Groundwater level and flow can be determined using a system of piezometers. A piezometer is essentially a monitoring well which is constructed to isolate a specific hydrogeologic environment for the measurement of water level or piezometric head. An example of a piezometer installation is shown in Figure F.5 (11). The measurement of piezometric head in two or more locations will allow the calculation of groundwater flow rates as illustrated in Figure F.6 (11). Methods of determining piezometric head include lowering a chalked measuring tape, a tape attached to a float, or a conductivity probe into the piezometer. Where direct vertical access to a piezometer is not available an electrical or pneumatic pressure tranducer can be permanently installed in the piezometer at the time of construction.

(b) Sampling for Physical and Chemical Characteristic Determination. Samples for physical and chemical characteristic determination can be taken from a monitoring well or piezometer. In a piezometer the isolation of a specific pressure environment by means of a cement grout or bentonite seal will also prevent contamination of the environment by surface water or water from higher elevations within the aquifer. However, where the purpose of sampling is to detect the presence of leachate the area to be isolated deserves special consideration. Leachate may tarvel in a narrow band within the upper, lowever, or mid-depth of an aquifer as illustrated in Figure F.7 (11). A piezometer that samples only one depth within the aquifer may not detect a leachate plume even though significant contamination of the aquifer is occurring. However, if a well is screened over the entire depth of the aquifer the leachate sampled may be diluted with sufficient volumes of uncontaminated water to make detection difficult, particularly during the early stages of groundwater contamination. An additional problem of this type of construction is that the monitoring well itself provides a conduit for the spread of leachate within the

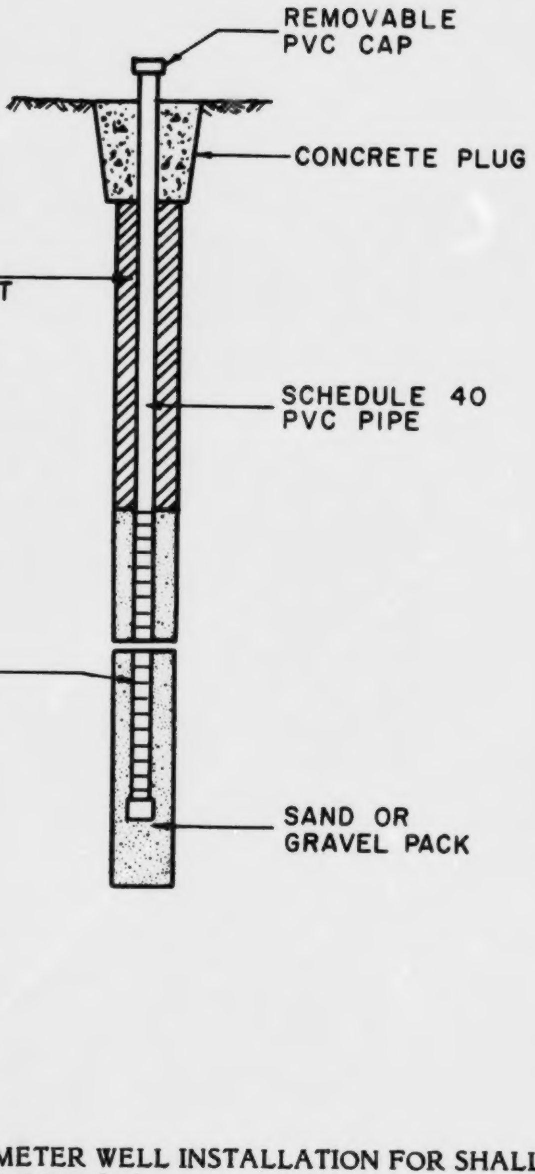
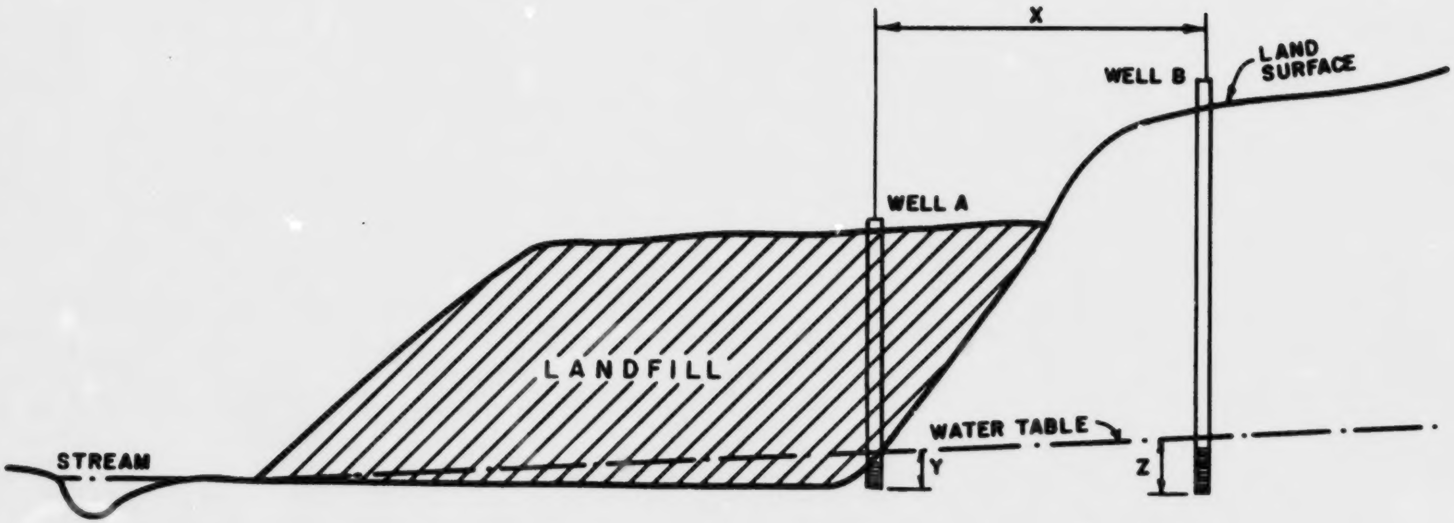

REMOVABLE
PVC CAP
CONCRETE PLUG
CEMENT OR
BENTONITE GROUT
SCHEDULE 40
PVC PIPE
SLOTTED SCHEDULE
40 PVC PIPE
SAND OR
GRAVEL PACK

FIGURE F.5 PIEZOMETER WELL INSTALLATION FOR SHALLOW GROUNDWATER MONITORING (11)


X
WELL B
LAND SURFACE
WELL A
LANDFILL
WATER TABLE
STREAM
Y
Z

Q = PIA
Where:
Q = Underflow
P = Permeability
I = Gradient
A = Area

P is estimated by pumping tests or injection tests in Wells A and B, or by examination of geologic samples removed during drilling

I = [z (meters) - y(meters)] ÷ x(meters)
A = (y) x (horizontal length of contact between the landfill and high ground)

FIGURE F.6 ESTIMATING RATE OF LANDFILL UNDERFLOW (11)

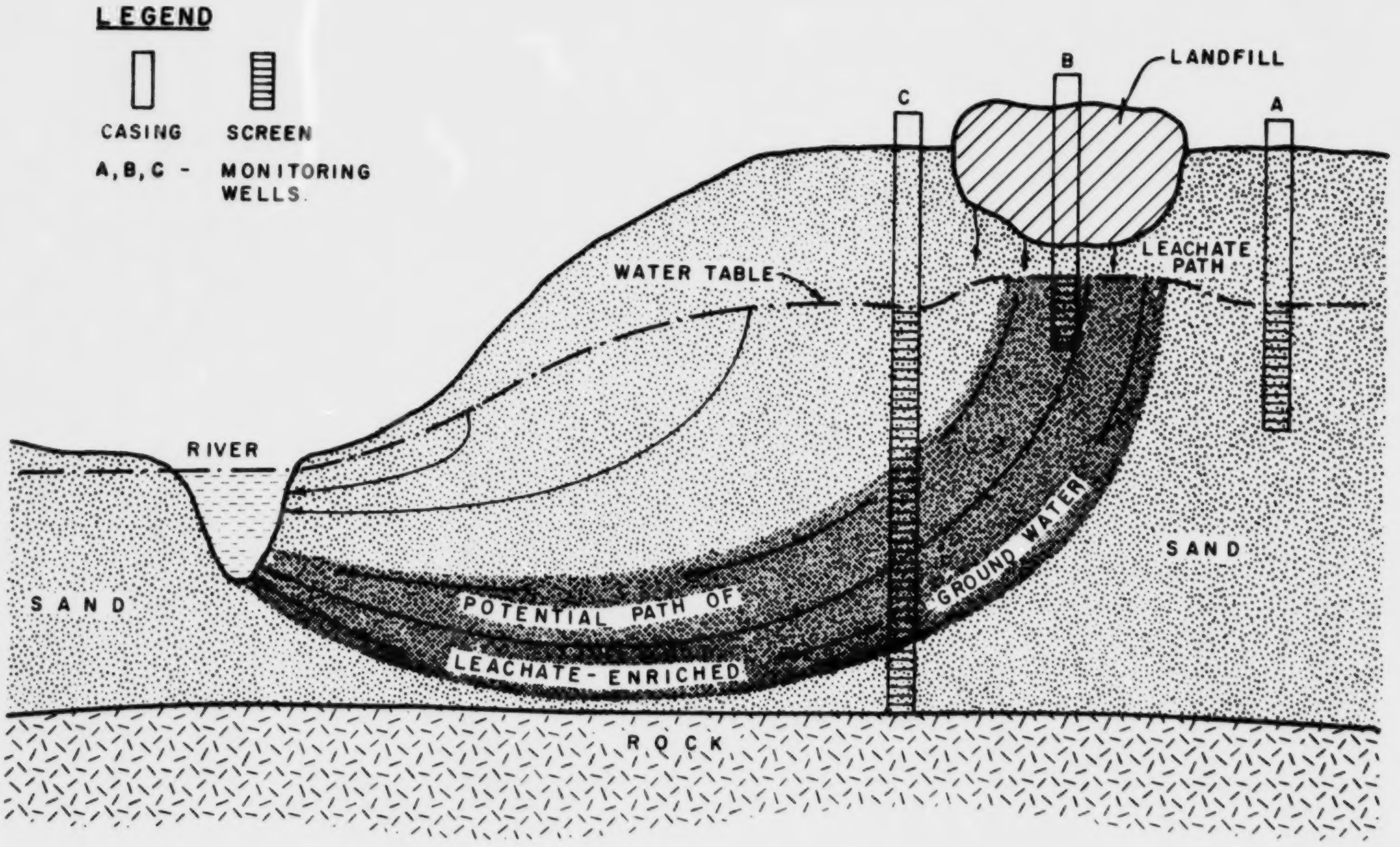

LEGEND
CASING
SCREEN
A, B, C - MONITORING WELLS.
B
LANDFILL
C
A
LEACHATE PATH
WATER TABLE
RIVER
SAND
POTENTIAL PATH OF
LEACHATE-ENRICHED
GROUND WATER
SAND
ROCK

FIGURE F.7 MONITORING NETWORK FOR AQUIFERS WITH INTERGRANUAL POROSITY - VERTICAL FLOW PATTERNS (11)

aquifer. A solution to this problem, recommended where the aquifer is greater than 30 metres in vertical thickness, is to sample the upper, lower and mid-depths of the aquifer at each monitoring location (11). This can be done by constructing a number of wells or piezometers at each monitoring location or by completing a number of wells on one drilled hole. This is illustrated in Figure F.8 (11). The critical feature of this technique is the use of an impermeable sealing material to isolate each vertical interval from which samples are to be taken. Where the aquifer is less than 15 metres in vertical thickness, one well screened over the depth of the aquifer should be sufficient to detect the presence or absence of leachate (11).

Prior to sampling a well stagnant water must be removed from the casing, allowing the entrance of water characteristic of conditions within the aquifer. It has been recommended that three to five casing volumes be removed (11) or that the well be pumped until chemical analyses show consistent composition (12). Equipment provided for sampling of wells must therefore be capable of removing considerable volumes of water. A hand bailer, the simplest sampling device, would generally be unsuitable. The use of vacuum pumps or air lift pumps must be approached with caution because these pumps can induce changes in the chemical composition of the sample (12). A satisfactory but relatively expensive means of obtaining a sample is a submersible pump. Where direct vertical access to a well is not available a submersible pump can be permanently installed.

F.4.2 Location and Accessibility. Suitable locations for permanent groundwater monitoring facilities can only be determined after an initial hydrogeologic study has been conducted. Such a study will indicate the following (11):

- the location and permeabiity of underlying geologic formations;
- the depth to the water table;
- the types, sizes and interconnections of the underlying aquifers;
- the natural rate and direction of flow of groundwater; and
- the rate of site infiltration relative to total groundwater flow.

The number, location, depth and types of monitoring wells and piezometers necessary to detect leachate entering and moving in the groundwater can be determined from this information. Although the monitoring network design will be highly site-specific the essential elements can be defined by assuming a very simple groundwater flow system. Using this approach one report (11) has outlined a system comprising five locations for monitoring groundwater adjacent to a landfill (Figure F.9) (11).

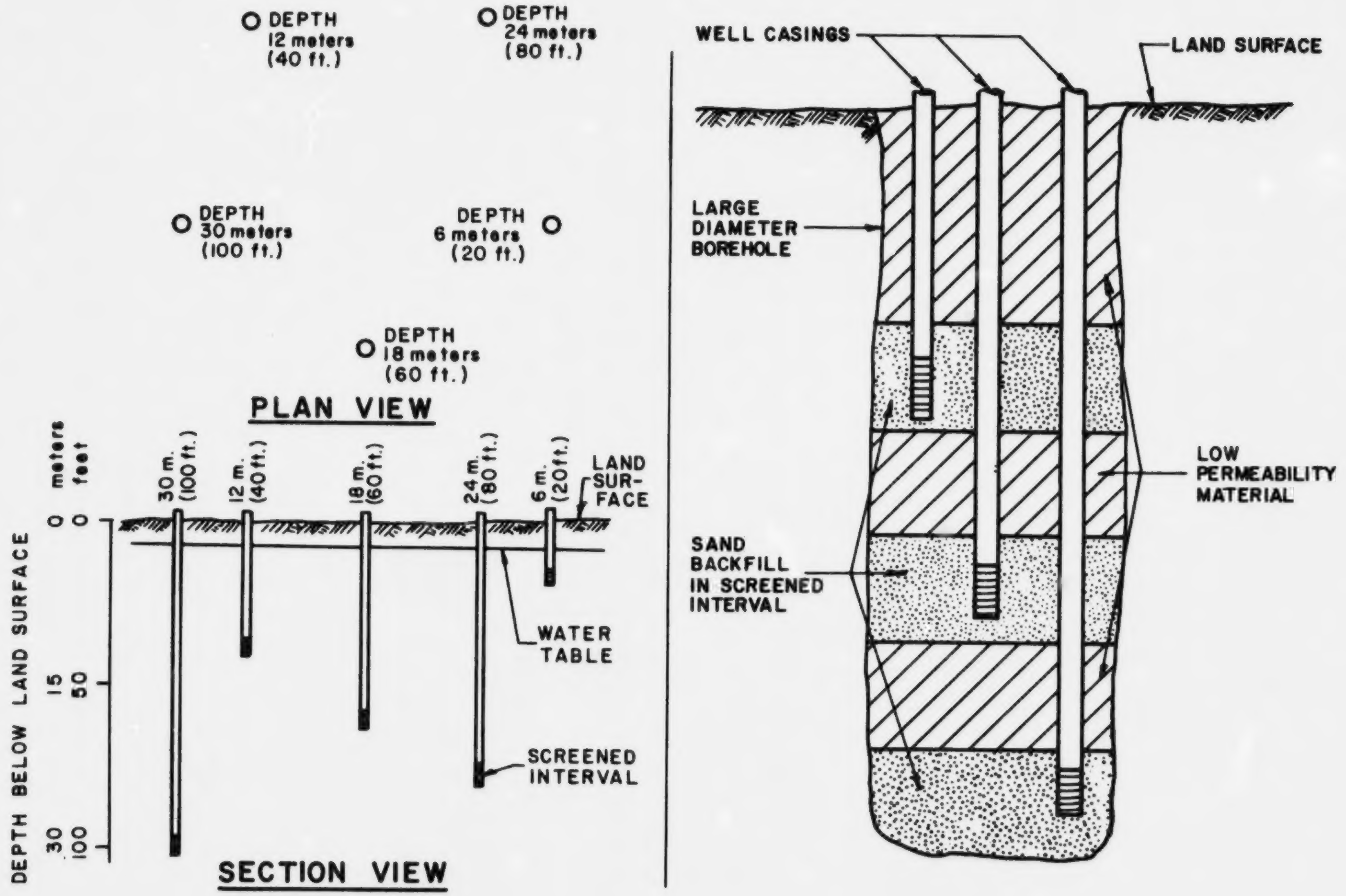

DEPTH 12 meters (40 ft.)
DEPTH 24 meters (80 ft.)
DEPTH 30 meters (100 ft.)
DEPTH 6 meters (20 ft.)
DEPTH 18 meters (60 ft.)
PLAN VIEW
DEPTH BELOW LAND SURFACE
meters
feet
0
0
15
50
30
100
30 m. (100 ft.)
12 m. (40 ft.)
18 m. (60 ft.)
24 m. (80 ft.)
6 m. (20 ft.)
LAND SUR-FACE
WATER TABLE
SCREENED INTERVAL
SECTION VIEW
WELL CASINGS
LAND SURFACE
LARGE DIAMETER BOREHOLE
LOW PERMEABILITY MATERIAL
SAND BACKFILL IN SCREENED INTERVAL

FIGURE F.8 TYPICAL WELL CLUSTER CONFIGURATIONS (11)

Well "A" in Figure F.9 is used to monitor background water quality. It is located far enough up gradient from a waste pond or landfill to ensure that leachate will not enter the well. This is a particularly important consideration where the disposal area has the potential to create a groundwater mound, causing a local flow of leachate in a direction different from that of the natural groundwater flow. The minimum safe distance from the disposal area and the potential for creating a groundwater mound can be estimated from the results of the initial hydrogeologic study.

Well "B" in Figure F.9 is located beneath the waste pond or landfill. It is advantageous to construct a well of type B prior to construction of the waste pond or landfill seepage control facilities. Monitoring equipment can be permanently installed in the well and accessed from a remote location as shown in Figure F.10. This construction eliminates the need to disturb the site liner and reduces the possibility of leachate migrating downward to the aquifer along the monitoring well casing. It also reduces the potential for damage to monitoring facilities during landfill operations and facilitates access to the monitoring location if pond disposal is practiced. An alternative is to construct a conventional well immediately at the toe (downgradient to) of the disposal area. This has the advantage of accessibility should problems develop with monitoring equipment in the well.

The type C monitoring locations in Figure F.9 are down gradient and close to the disposal area to allow early detection of a leachate plume. Depending on the underlying hydrogeologic environment these monitoring sites may each comprise a cluster or nest of wells, as described in the preceding section, to monitor the upper, lower, and mid-depths of the aquifer.

The number and location of monitoring facilities down gradient from the disposal area are highly dependent on the nature of the underlying hydrogeologic environment, as determined by the initial hydrogeologic study. If the aquifer is in fractured rock or carbonate rock in which discrete but unknown groundwater flow channels exist the number of monitoring locations may have to be increased but the detection of a leachate plume produced by the disposal site will still be uncertain.

Ultimately the monitoring network may include wells placed at greater distances down gradient from the disposal area to determine the degree of attenuation of the leachate in the aquifer. These wells, however, can generally be constructed after disposal operations have begun and when a leachate plume can be detected in wells near the disposal site.

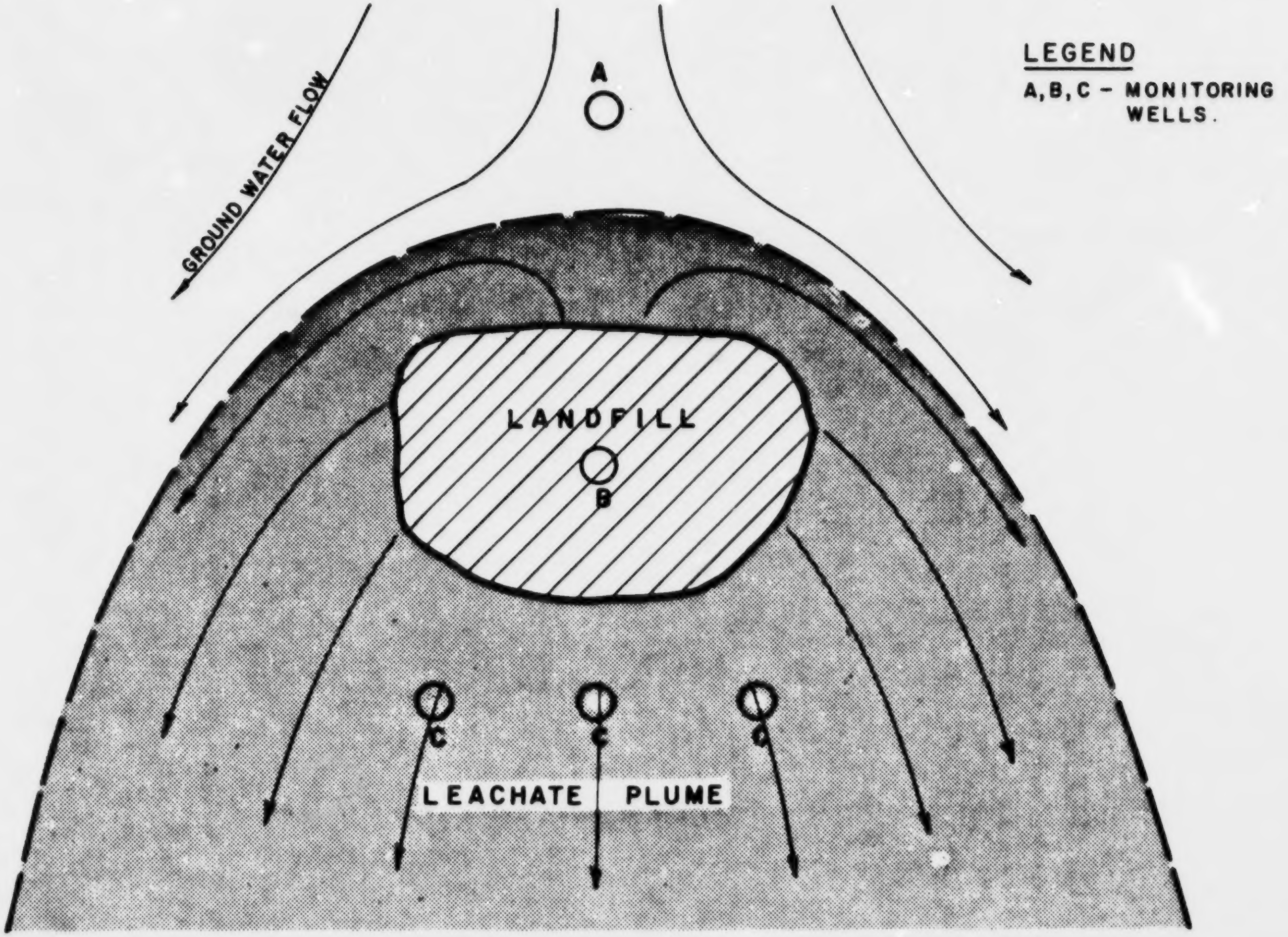

GROUND WATER FLOW
A
LEGEND
A, B, C – MONITORING WELLS.
LANDFILL
B
C
C
C
LEACHATE PLUME

FIGURE F.9 MONITORING NETWORK FOR AQUIFERS WITH INTERGRANULAR POROSITY - AREA FLOW PATTERNS (11)

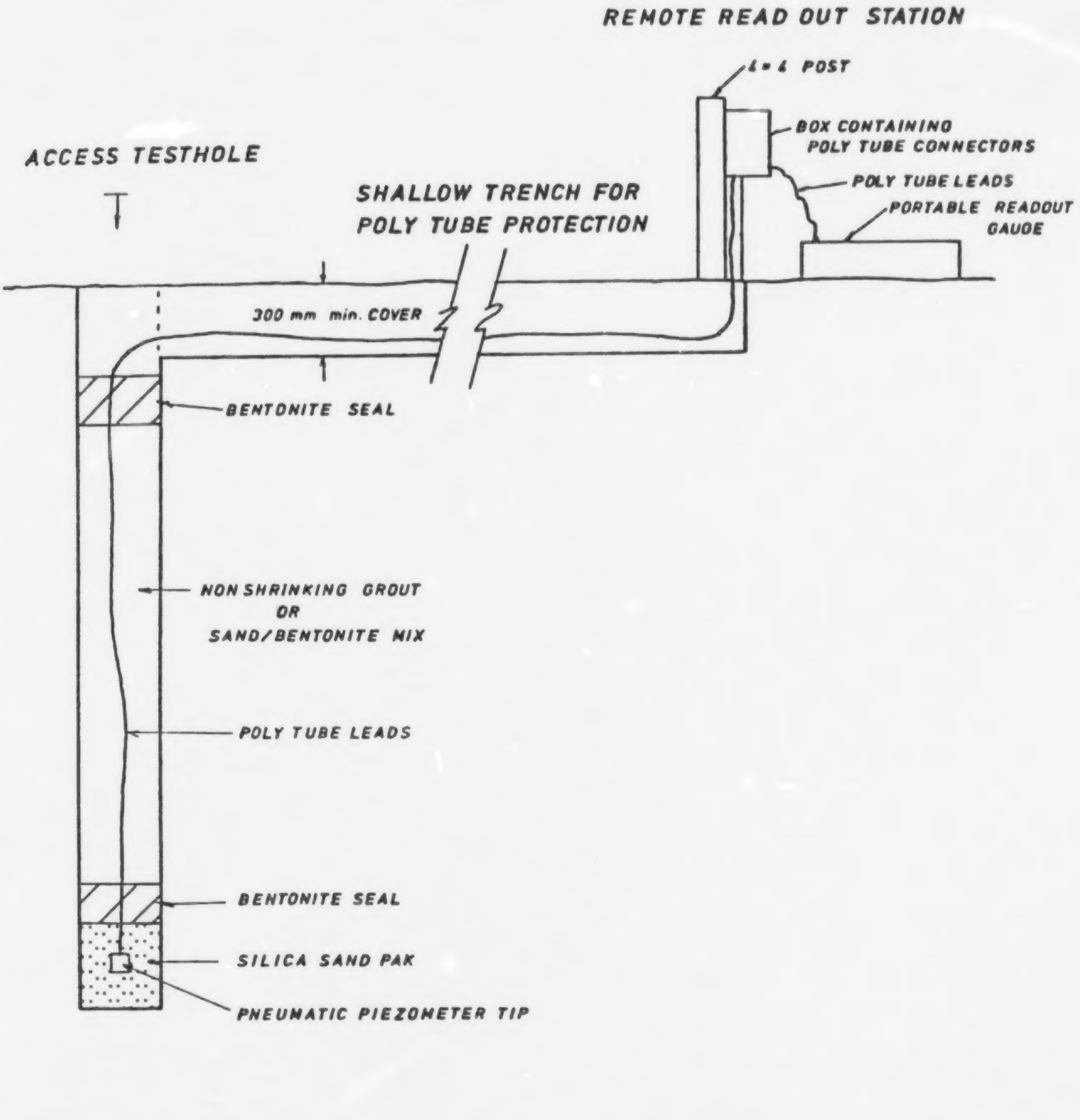

REMOTE READ OUT STATION
4 x 4 POST
BOX CONTAINING POLY TUBE CONNECTORS
POLY TUBE LEADS
PORTABLE READOUT GAUGE
ACCESS TESTHOLE
SHALLOW TRENCH FOR POLY TUBE PROTECTION
300 mm min. COVER
BENTONITE SEAL
NON SHRINKING GROUT OR SAND/BENTONITE MIX
POLY TUBE LEADS
BENTONITE SEAL
SILICA SAND PAK
PNEUMATIC PIEZOMETER TIP

FIGURE F.10 CONSTRUCTION OF PIEZOMETER FOR REMOTE ACCESS

RECOMMENDATION R306. For solid fuel storage and for solid and liquid waste storage and disposal sites, a permanent system of appropriately located piezometers and wells should be installed to monitor the quality, quantity and direction of flow of groundwater.

Disposal operations may themselves change the local groundwater flow pattern, particularly if they involve ponding or an increase in infiltration of precipitation into the site. To adequately assess the impact of these changes baseline data on the natural groundwater flow system is necessary.

RECOMMENDATION R307. A program of pre-operational monitoring of groundwater regimes that may be affected by power station activities should be established one year prior to construction.

F.5 Receiving Environment

F.5.1 Equipment and Facilities. The focus of this section has been the selection and location of monitoring facilities that should be considered during the design phase. Although monitoring in the receiving surface environment requires very few permanent monitoring facilities or plant design considerations, baseline, pre-operational data concerning the receiving environment are essential for subsequently determining the change, if any, in receiving water quality as a result of utility operations and the effect of this change on the aquatic biota. The design phase is an appropriate opportunity to begin such monitoring. Monitoring during the construction phase may not provide suitable baseline data because of disturbances (increased runoff, siltation, disturbance to bottom sediments, etc.) during construction.

Because the environmental impact of the facility will be determined by comparing pre-operational and operational data, sampling equipment, techniques and locations and analytical procedures should be consistent between the two periods.

F.5.2 Monitoring Parameters. Physical, chemical, and biotic characteristics of the receiving environment can be expected to change seasonally and perhaps year to year. To obtain reliable baseline data at least three years of monitoring will be required prior to plant start up. An excellent description of the wide variety of equipment which may be used in monitoring of the receiving environment is contained in reference 13.

The receiving environment is an ecosystem which contains a wide variety of components which interract in complex and often poorly understood ways. Assessment of the direct and indirect effects of a steam electric power generation facility on this ecosystem requires consideration of a large number of parameters.

Water quality parameters such as pH, temperature, dissolved oxygen, total suspended solids, total dissolved solids and metals provide a direct indication of the effect of power plant operation on the receiving environment. The contaminants of environmental interest at a specific site will depend on the type of generation facility (i.e., fossil or nuclear).

Sediments provide a good indicator of changing environmental conditions. Accumulation of adsorbed heavy metals and other power plant constituents will provide a useful tool for determining environmental stress.

Benthic (bottom dwelling) organisms are particularly useful as indicators of pollution because they are relatively immobile and cannot avoid polluted areas, and because they form characteristic communities. Changes in the diversity of organisms within these communities may reflect the effects of pollution on such factors as growth, reproduction and behaviour. It has been indicated that benthic communities do not reflect average levels of pollution but are more likely to reflect the extremes (14).

Periphyton (organisms that grow on surfaces of underwater substrates such as rocks and plants) are important because they are primary producers in the food chain. They are good indicators of water quality and respond rapidly to pollution (13). Some organisms in this group are immobile and thus cannot avoid pollution.

Plankton have little or no ability to control their movement and will drift with the current. For this reason zooplankton are considered indicators of upstream conditions and not conditions at the point of sampling (14). However, for this same reason they are particularly susceptible to entrainment in once-through cooling systems. As indicated in Appendix D the impact of cooling system mortality on ichthyoplankton (fish eggs and larvae) populations is important because of their long generation times. A knowledge of ichthyoplankton population dynamics is essential if power plant outages are to be scheduled to coincide with periods of maximum potential entrainment as recommended in Appendix D. Ichthyoplankton numbers may also indicate changes in breeding habitat.

Phytoplankton are important indicators of temperature effects on the receiving water. As temperature increases a general shift in species occurs from diatoms, which are desirable as primary producers in the food chain, to blue-green algae which are less productive and a potential nuisance (14).

Macrophytes (rooted plants) are of concern mainly because of the problems created by the excessive growth associated with discharges of heat and nutrients.

Adult fish may have commercial and recreational importance. Changes in populations may be a result of mortality or of avoidance of heated discharges, an abundance or lack of food, or changes in spawning areas. The accumulation of contaminants such as heavy metals in the flesh of fish may occur even at very low levels of these contaminants in the receiving environment.

A summary of the parameters that may be considered in an environmental monitoring program is contained in Table F.2.

F.5.3 Location. Locations of sampling stations for thermal discharge sites have been recommended as shown in Figure F.11 (14). The method involves locating transects across a river at intervals determined by the thermal plume temperature relative to the natural temperature. For pre-operational studies it will be necessary to estimate the extent of the thermal plume. To sample all organisms except fish four sampling stations are located along each transect at 10, 30, 70, and 90 percent of the river width. Samples of adult fish are taken from three equal-width sections of the river across each transect. A variation of this technique for sampling in large bodies of water is shown in Figure F.12 (14). During the pre-operational phase, when water quality throughout the zone of interest can be expected to be homogenous, the number of sampling locations for chemical characteristic determination may be reduced. Each sampling location is marked with a permanently anchored buoy. In locating sampling stations, particular attention should be given to establishing areas of unique biological interest.

RECOMMENDATION R308. A program of pre-operational monitoring of the receiving aquatic environment should be established at least one year prior to the beginning of construction and should:

(i) establish permanent monitoring locations,

(ii) establish sampling procedures and analytical procedures that include parameters which relate to steam electric generation activities,

(iii) determine baseline receiving water quality,

(iv) determine baseline aquatic sediment characteristics,

(v) determine baseline biotic conditions with respect to seasonal variations of populations, species, growth rates, habitat, and reproductive activities.

F.6 Laboratory and Data Recording Facilities

F.6.1 Laboratory Facilities. Alternative methods for the analysis of effluent for the criteria specified in recommendation R211 are presented in Table F.3. Station laboratories have analytical capabilities for conventional water quality parameters (e.g., pH, dissolved oxygen, suspended solids, dissolved solids, etc.). It may be appropriate to

TABLE F.2 SUGGESTED ENVIRONMENTAL MONITORING PROGRAM

Environmental Sector	Parameters	Frequency	Comments
Water	pH, Temperature, Dissolved Oxygen, Suspended Solids	- Once per month for 3 years prior to and after first firing, including one year prior to construction	This will be useful information for interpretation of impacts observed in other sectors and also for determining operating efficiency of cooling water and other systems
	Dissolved Solids, Alkalinity Total Organic Carbon, Hardness Iron, Copper, Chromium, Zinc, Nickel, Vanadium, Oil and Grease, Tritium, Radionuclides (Salinity for Marine Waters)	- Seasonally for at least 3 years prior to and after first firing - Descrease frequency after 3 years	
Aquatic Sediments	Heavy Metals and Oil and Grease Radionuclides	- Once during pre-operational period Once every 3 years during post-operational period	This will provide information on the accumulation of waste products (particularly heavy metals) in the aquatic environment. This information will also be useful in interpreting other observed impacts.
Biota	Benthos - diversity and community structure	- Twice per year (summer/winter) for each year of monitoring	Shifts in diversity and/or community structure of benthic organisms in vicinity of thermal plants will indicate degree and extent of impacts on receiving waters.
	Periphyton - numbers and diversity	- Twice per year (summer/winter) for each year of monitoring	Primary producers in food chain. Respond rapidly to changes in water quality.
	Plankton (Phyto, Zoo and Ichthyo) Numbers and population dynamics, species diversity	- Once per month, more frequently when populations increase in near shore areas	Important in food chain, susceptible to entrainment and damage in cooling systems, blue-green algae a nuisance.
	Macrophytes - growth rate, diversity community structure	- At least twice during growth period	Changes in growth rate or shifts in diversity and/or community structure will indicate degree and extent of impacts on receiving waters.
	Adult fish - numbers, diversity, growth rates, spawning activities heavy metal and radionuclide content of tissue	- At lest twice per year or according to spawning habits - Once per year for examination of tissues	Will indicate avoidance behaviour, change in spawning habits, loss of species upon which they are dependent, presence of low levels of metal contaminants.

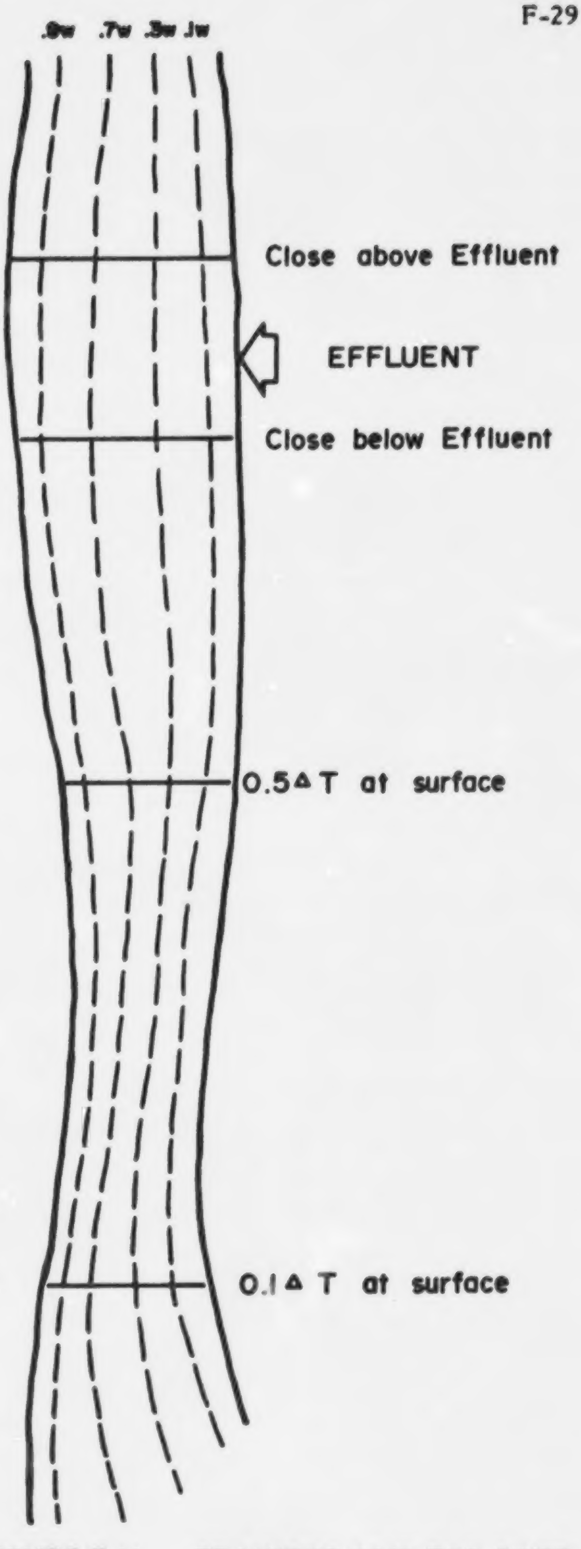

.9w
.7w
.3w
.1w
Close above Effluent
EFFLUENT
Close below Effluent
0.5Δ T at surface
0.1Δ T at surface

FIGURE F.11 TRANSECT GRID FOR RIVER SAMPLING (14)

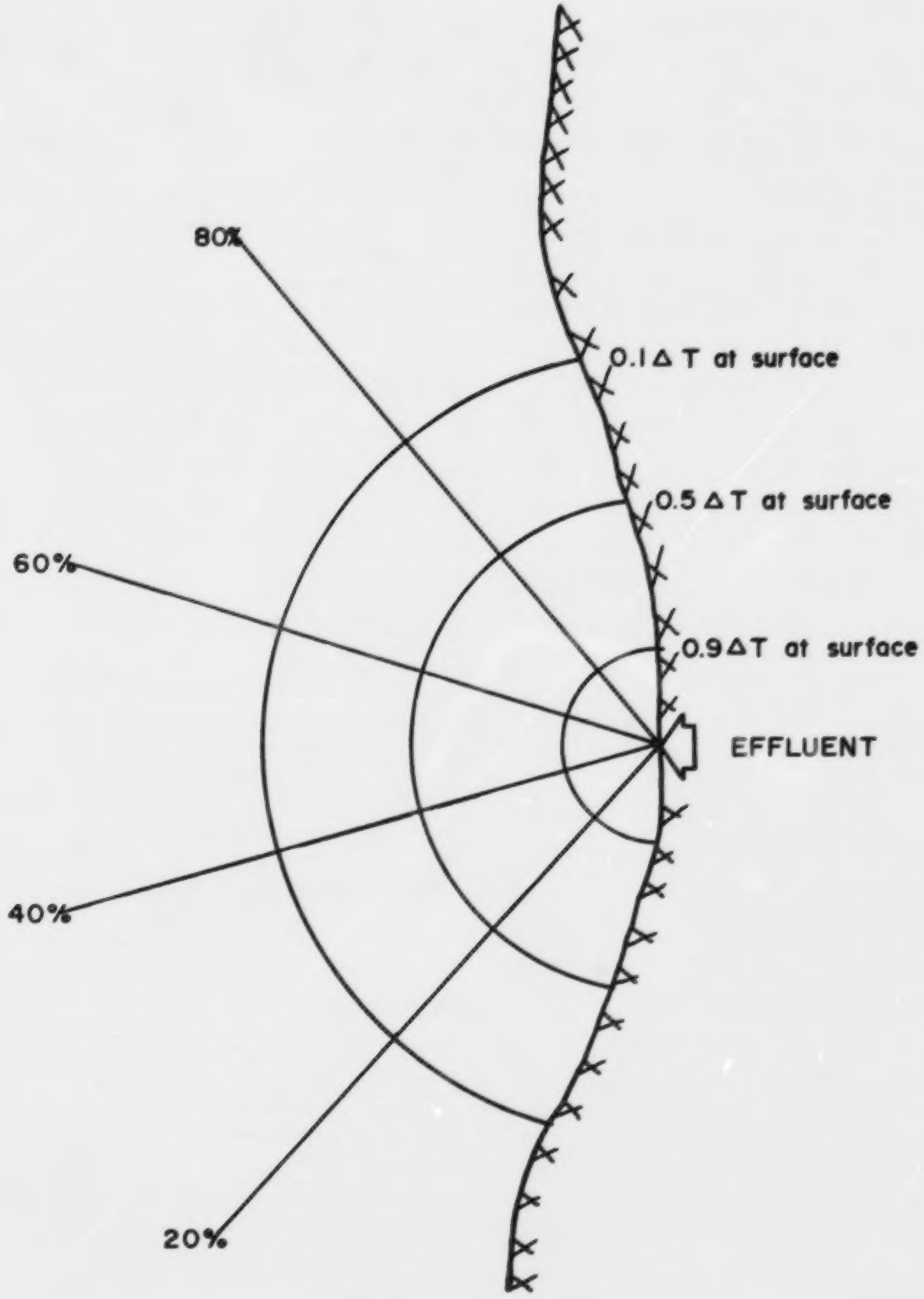

80%
60%
40%
20%
0.1 ΔT at surface
0.5 ΔT at surface
0.9 ΔT at surface
EFFLUENT

FIGURE F.12 TRANSECT GRID FOR LAKE OR OCEAN SAMPLING (14)

provide laboratory analytical facilities (e.g., atomic absorption) for parameters listed in R211 if the criteria are likely to be exceeded rather than to ship the samples to more fully equipped laboratories. Advantages of maintaining station analytical facilities are that "problem" discharges can be quickly identified, enabling prompt remedial action, and the facilities will probably be useful for a number of process control applications.

F.6.2 Control Room Facilities. Power plant control rooms have alarms to indicate process excursions or equipment malfunction (e.g., motor trip, valve opening failure, high temperature, etc.). Environmental parameters monitored by on-line instrumentation (pH, chlorine, temperature) could be integrated into this system and set points established so that an alarm would be annunciated in the event of an excursion. This would facilitate prompt operator response to environmental problems.

Modern power plant control rooms are equipped with data loggers which store values of parameters important to the steam electric generation process. These parameters include pressures, temperatures and conductivity of process streams and power drawn by rotating electrical equipment.

Some parameters of environmental interest may also be readily recorded on a central data logger. This may involve automatic recording of data from on-line monitoring equipment as well as the input of laboratory analytical data. This provision would facilitate environmental reporting.

RECOMMENDATION R309. ***Laboratory, control room and data logging facilities should be provided so that:***

(i) parameters of environmental concern in water and wastewater samples can be expeditiously analyzed,

(ii) excursions of parameters of environmental interest monitored by on-line instrumentation can be annunciated in a central control room, and

(iii) values of parameters of environmental interest can be stored and readily retrieved.

F.7 Tentative Monitoring Requirements - Operations Phase

Selection and location of monitoring facilities at the design phase will depend on monitoring requirements during the operations phase. Tentative operations phase monitoring requirements are therefore presented in Tables F.4, F.5 and F.6. These are to be used as a guide only and will be refined in the Operations Phase Code.

The frequency of monitoring indicated in Tables F.5 and F.6 may be decreased as data is accumulated to show the facility consistently meets environmental criteria.

TABLE F.3 METHODS FOR ANALYSIS OF WASTEWATERS FROM STEAM ELECTRIC GENERATING STATIONS

	Methods of Analysis			
Parameters	ASTM[a]	APHA[b]	U.S. EPA[c]	Environment Canada[d]
pH	Electrometric, p. 191 (Designated) D1293-78)	Electrometric, p. 460 (Part 424)	Electrometric, p. 239	Electrometric
Suspended Solids	Gravimetric, p. 164 (Designated) (D1888-67)	Gravimetric, p. 94 (Part 208, Section C)	Gravimetric, p. 266	Gravimetric
Dissolved Solids	Gravimetric, p. 164 (Designated) D188-67, Method A	Gravimetric, p. 93 (Part 208, Section D)	Gravimetric, p. 268	Gravimetric
Oil and Grease	Gas Chromatography, p. 708 (Designated D3328-78, Method A)	Gravimetric - Soxhlet p. 518 (Part 502)	Gravimetric - Soxhlet p. 226	
	Fluorescence, p. 720 (Designated D3650-78, Method B)	Gravimetric - Partition p. 515 (Part 502)	Gravimetric - Partition p. 229	
	Infrared, p. 727 (Designated D-3414-75T, Method C)	Infrared, p. 516 (Part 502)	Infrared, p. 232	
Iron (Total)	Colorimetric-Orthophenanthroline, p. 374 (Designated D1068-77, Method A)	Colorimetric, p. 208 (Part 310)	Atomic Absorption, p.110	Atomic Absorption
	Colorimetric-Bathophenanthroline, p. 377 (Designated D1068-77, Method B)	Atomic Absorption, p. 213		
	Atomic Absorption, p. 379 (Designated D1068-77, Method C and D)			
Nickel (Total)	Colorimetric-Carbamate, p. 419 (Designated D1886-77, Method A)	Colorimetric-Heptoxime p. 232 (Part 316)	Atomic Absorption,	Atomic Absorption
	Colorimetric-Glyoxime, p. 422 (Designated D1886-77, Method B)	Colorimetric-Dimethylglyoxime, p. 233 (Part 316)		

TABLE F.3 METHODS FOR ANALYSIS OF WASTEWATERS FROM STEAM ELECTRIC GENERATING STATIONS (Cont'd)

	Methods of Analysis			
Parameters	ASTM[a]	APHA[b]	U.S. EPA[c]	Environment Canada[d]
Copper (Total)	Colorimetric-Neocuproine, p. 333 (Designated D1688-77, Method A & B)	Colorimetric-Neocuproine p. 196, (Part 308)	Atomic Absorption, p. 108	Atomic Absorption
	Colorimetric-Cuprethol, p. 338 (Designated D1688-77, Method C)	Colorimetric-Bathocuproine, p. 198 (Part 308)		
	Atomic Absorption, p. 339, Method D and E)	Atomic Absorption, p. 195 (Part 308)		
Zinc (Total)	Colorimetric-Zincon, p. 516 (Designated D1691-77 Method A & B)	Colorimetric-Zincon p. 268 (part 323)	Atomic Absorption, p. 155	Atomic Absorption
	Atomic Absorption, p. 519 (Designated D1691-77 Method C & D)	Colorimetric-Dithizone p. 263 (Part 323)		
Chromium (Total)	Colorimetric-Permanganate Oxidation, p. 316 (Designated D1687-77	Atomic Absorption, p. 262 (Part 323)	Atomic Absorption, p. 105	Atomic Absorption
	Colorimetric-Hypochlorite Oxidation p. 318 (Designated D1687-77 Method B)	Colorimetric-Diphenylcarbazide, p. 192 (Part 307)		
Chromium (Total)	Colorimetric-Alkaline-Persulphate Oxidation, p. 320 (Designated D1687-77, Method C)	Atomic Absorption, p. 192 (Part 307)		
	Atomic Absorption, p. 326 (Designated D1687-77, Method D)			

[a] ASTM - 1978 Annual Book of ASTM Standards, American Society for Testing and Materials, Part 31, Water, 1978.

[b] APHA - Standard Methods for the Examination of Water and Wastewater, APHA, AWWA, 14th Edition, 1975.

[c] U.S. EPA - Manual of Methods for Chemical Analysis of Water and Wastes, U.S. Environmental Protection Agency, 1974.

[d] Environment Canada - Analytical Methods Manual, Environment Canada, Water Quality Branch, 1974.

Note: Metals analyses should be for total (dissolved and suspended) metal. Digestion may therefore be rquired.

TABLE F.4 TENTATIVE MONITORING REQUIREMENTS FOR TYPE 1 STREAMS - OPERATIONS PHASE

	Monitoring Requirements		
Source	Parameters	Frequency	Comments
Condenser Cooling Water	Temperature	Continuous	Monitor at inlet and outlet to condenser
	Chlorine	Continuous during injection	-
	Flow	Daily	-
Auxiliary Cooling Water	Temperature	Continuous	-
	Flow	Daily	-

TABLE F.5 TENTATIVE MONITORING REQUIREMENTS FOR TYPE 2 STREAMS - OPERATIONS PHASE

Source	Monitoring Requirements		Comments
	Parameters	Frequency	
Boiler Cleaning	pH	Continuous during discharge	-
	Total suspended solids & trace metals (Fe, Cu, Cr, Ni, Zn)	Minimum of 3 grab samples during discharge	Composite grab sample for analysis
	Volume	-	Record total volume discharged
Water Treatment Plant	pH	Continuous during discharge	-
	Total suspended solids	Daily grab	-
	Volume	-	-
Coal Pile Runoff	pH	Continuous during discharge	-
	Total suspended solids & trace metals (Fe, Cu, Cr, Ni, Zn)	Daily grab	Composite grab samples and analyze once a week
	Flow	Continuous during discharge	-
Air Preheater Cleaning	pH	Continuous during discharge	-
	Total suspended solids & trace metals (Fe, Cu, Cr, Ni, and Zn plus V for oil-fired generating stations	Minimum of 3 grab samples during discharge	Composite grab samples for analysis
	Flow	Continuous during discharge	-
Floor Washings	pH, total suspended solids and oil	Minimum of 3 grab samples collected per month	Composite grab samples for analysis
	Flow	-	Record total volume discharged
Dyked Tank Farm Area	Oil	Grab sample collected for each drainage	Analyze grab samples
	Volume	-	Record total volume discharged

TABLE F.5 TENTATIVE MONITORING REQUIREMENTS FOR TYPE 2 STREAMS - OPERATIONS PHASE (Cont'd)

Source	Monitoring Requirements		Comments
	Parameters	Frequency	
Boiler Blowdown	pH	Grab sample collected for each blowdown	Analyze grab samples
	Volume	-	Record total volume discharged
Recirculating Cooling System Blowdown	pH, total suspended solids and metals (Fe, Cu, Cr, Ni, Zn)	Grab sample collected at each blowdown	Analyze grab sample
	Volume	-	Record total volume discharged
Ash System Blowdown	pH	Continuous during discharge	-
	Total suspended solids	Daily grab	Composite grab samples and analyze once a week
	Metals (Fe, Cu, Zn, Cr, Ni)	Daily grab	Composite grab samples and analyze once a week
	Flow	Continuous during discharge	Record total volume discharged
Yard and Stormwater Containment Area Drainage	pH	Grab samples collected once per month	Analyze grab sample
	Total suspended solids	Grab samples collected once per month	Analyze grab sample
	Oil and grease	Grab samples collected once per month	Analyze grab sample
	Flow	Continuous	Record total volume discharged
Ash and FGD Waste Disposal Area Runoff	pH	Grab samples collected once per month	Analyze grab sample
	Total suspended solids	Grab samples collected once per month	Analyze grab sample
	Metals (Fe, Cu, Zn, Cr, Ni)	Grab samples collected once per month	Analyze grab sample
	Flow	Continuous	Record total volume discharged
Sanitary Waste	pH	Grab samples collected once per month	Analyze grab sample
	Total suspended solids	Grab samples collected once per month	Analyze grab sample
	Flow	Continuous	

TABLE F.6 TENTATIVE ENVIRONMENTAL MONITORING PROGRAM - OPERATIONS PHASE

Environmental Sector	Monitoring Requirements		Comments
	Parameters	Frequency	
Water	pH, Temperature, Dissolved Oxygen, Suspended Oxygen, Suspended Solids	- Once per month for 3 years prior to and after first firing, one year prior to construction	This will be useful information for interpretation of impacts observed in other sectors and also for in other sectors and also for cooling water and other systems
	Dissolved Solids, Alkalinity Total Organic Carbon, Hardness Iron, Copper, Chromium, Zinc, Nickel, Vanadium, Oil and Grease, (Salinity for Marine Waters)	- Seasonally for at least 3 years prior to and after first firing - Decrease frequency after 3 years	
Aquatic Sediments	Heavy Metals and Oil and Grease	- Once during pre-operational period. Once every 3 years during post-operational period.	This will provide information on the accumulation of waste products (particularly heavy metals) in the aquatic environment. This information will also be useful in interpreting other observed impacts.
Biota	Benthos - diversity and communicy structure.	- Twice per year (summer/winter) for each year of monitoring.	Shifts in diversity and/or community structure of benethic organisms in vicinity of thermal plants will indicate degree and extent of impacts receiving waters.
	Macrophytes - growth rate, diversity, community structure.	- During growth period.	Changes in growth rate or shifts in diversity and/or community structure will indicate degree and extent of impacts on receiving waters.
Biota	Spawning activities of resident fish populations	- During spawning seasons.	Shifts in breeding areas will indicate possible environmental impacts on receiving waters.
	Plankton (Phyto and Zoo) - % mortality of organisms passing through cooling water systems.	- Once per month in cooling water systems.	Should provide information on impact of cooling water system on planktonic organisms.
	Fish Larvae	- Same as above	Should provide information on impact of cooling water system on planktonic organisms.
	Adult Fish - Impingement on screens (number or weight and species type)	- Daily for impingement	This information will be useful in determining impact of entertainment and impingement on fish populations as well as indicating whether or not fish have become contaminated by heavy metals.
	- Characterization of standing population in receiving water.	- Each year of monitoring program for population studies.	
	- Heavy metal content of tissue.	- One year pre-operational for heavy metal content. metal content.	
Hydrology	Ground and surface waters (quality and quantity)	- Continuous recording of quantity. Once monthly quality determination.	This information will be useful in determining impact of thermal statons on surface and groundwater quality and quantity.
	- Conductivity should be used as an indicator of changing quality.		
	- One heavy metal scan prior to first firing.		

Note: The above studies are minimum monitoring requirements. Pre and post-operational monitoring studies may require additional more detailed evaluation depending on site-specific characteristics.

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APPENDIX G

COST IMPLICATIONS

APPENDIX G - COST IMPLICATIONS

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APPENDIX G COST IMPLICATIONS

G.1 Purpose and Scope

The foregoing sections of this code have recommended a variety of measures designed to mitigate environmental concerns associated with steam electric power plant cooling systems and wastewaters. These recommendations will result in additional design features in some new steam-electric plant systems. This section examines the range of costs associated with such features and explores the probable cost impacts on customer electricity rates.

Costs are estimated for each additional design feature based on literature reported and estimated costs. Where a number of alternative environmental control systems exist relating to one recommendation, costs have been estimated for each for purposes of comparison only and cannot be used to determine the most appropriate technology.

The impact on customer electricity rates is assessed by developing models describing possible future power generation facilities. These models are generic and represent realistic combinations of individual environmental control features. The costs derived from the models are used to estimate: a) the percentage increase in the cost of constructing a new generating facility, and b) the percentage increase in the cost of power to the customer as a result of the codes of practice recommendations.

Costs developed are order of magnitude estimates only. In an independent review of this study by Monenco Consultants Ltd. costs were found, within the accuracy of the estimates, to be in agreement with those presented here (1).

G.2 Summary of Technical Implications of the Recommendations

In assessing the economic implications of the recommendations it is necessary to first define a starting point or base case that typifies current industry practice independent of these codes of practice. The cost of any additional features designed to mitigate the concerns expressed in the recommendations can then be considered as the incremental cost of complying with the recommendations. A summary of the recommendations, base case assumptions, and additional design features is presented in Table G.1.

The choice of base case assumptions is difficult because a wide variety of environmentally related systems currently exist at Canadian utilities and some are equal

TABLE G.1 SUMMARY OF RECOMMENDATIONS, BASE CASE ASSUMPTIONS, AND SYSTEM MODIFICATIONS

	Summary of Recommendation	Base Case	System Modifications	Location of Cost Data
101	Water withdrawal should be less than 10 per cent of near shore standing volume and 5 percent of total volume of lakes. The rate of withdrawal should not exceed 10 percent of the average flow of rivers.	A plant which does not meet the water withdrawal criteria because of a once-through cooling water system	a) A smaller plant with a once-through cooling system	Not Estimated
			b) A recirculating cooling system utilizing cooling towers, pond or canal	G.3.2(a)
			c) An offshore submerged intake beyond the littoral zone	G.3.2(b)
102	Auxiliary cooling systems should be designed for: i) minimum water use ii) maximum reuse of discharge	A once-through direct auxiliary cooling system with no provisions for minimization of water use or internal water reuse	a) The minimization of auxiliary cooling water use and the reuse of discharge water for other plant purposes	Not Estimated
			b) A total or partial recirculating cooling system using cooling towers, pond or canal	G.3.2(a)
103	Control over once-through cooling water flow rate should be considered by appropriate number and size of pumps, throttling capability	A small number of large cooling water pumps with no throttling	Additional pumps and throttling capability	Negligible Cost Impact
104	Planned outages should be scheduled to coincide with period of highest concern for ichthyoplankton entrainment	Outages on as required basis	Restricted scheduling of outages	Negligible Cost Impact
105	Intakes should normally be located offshore beyond the littoral zone	A shoreline intake	An offshore submerged intake beyond the littoral zone	G.3.2(b)
106	Locate intake location relative to outfall to: i) minimize recirculation of heated effluent ii) place longest length of piping on intake side	An intake and outfall configuration designed without regard to organism exposure time to heated discharges	An intake longer than the outfall	Negligible Cost Impact

TABLE G.1 SUMMARY OF RECOMMENDATIONS, BASE CASE ASSUMPTIONS, AND SYSTEM MODIFICATIONS (Cont'd)

	Summary of Recommendation	Base Case	System Modifications	Location of Cost Data
107	Intakes should be designed to minimize fish entrainment	No provision for minimizing fish entrainment	A velocity cap for an offshore submerged intake and intake opening totally above the lake bed	G.3.2(b)
108	For shoreline intakes, screens should be set flush with the shoreline and protrusions minimized	Intake screens that are not flush with the shoreline	Intake screens set flush with the shoreline and protrusions minimized	Negligible Cost Impact
109	i) Intakes should be equipped with a fish bypass and return system	No fish bypass and return system	A fish bypass and return system	G.3.2(c)
	ii) Shoreline intakes without a fish bypass and return system should have low approach velocity, no vertical flow in the forebay and provision for retrofitting a fish bypass and return system	Intake velocities greater than 15 cm/s and no provision for retrofitting a fish bypass and return system	Wider inlet and forebay and provision for retrofitting a fish bypass and return system	Not Estimated
110	Physical stresses to entrained organisms should be considered in selected cooling water pumps	Cooling water pumps are selected without consideration for stress to entrained organisms	Pumps are selected with consideration for stresses on entrained organisms	Negligible Cost Impact
111	i) Chemicals should be used for biofouling control only when demonstrated to be necessary	Chemicals used for biofouling control without demonstrated necessity	The use of mechanical biofouling control systems	G.3.2(e)
	ii) If chlorine is used for biofouling control its use should be minimized	Chlorine used without major efforts to minimize its use	Chlorine monitoring and minimization system which may include dechlorination. Chlorine used intermittently, one condenser at a time, during daylight hours and injected immediately upstream of condensers	G.3.2(f)
112	The use of chemicals which may cause environmental damage for corrosion, scaling, or silting control should be avoided. Where it is necessary, chemical use should be minimized and spent cleaning solutions should be treated before discharge.	Chemicals used for corrosion scaling or silting control are discharged without demonstration of need, knowledge of environmental effects, minimization attempts or treatment	a) The use of mechanical scaling and silting control systems, corrosion resistant materials or cathodic protection	G.3.2(e)
			b) Use of only those chemicals demonstrated not to cause environmental damage	G.3.3(c)
			c) The use of only the minimum amounts of chemicals demonstrated to be necessary	Not Estimated
			d) Treatment for off-line cleaning solutions	G.3.3(j)

TABLE G.1 SUMMARY OF RECOMMENDATIONS, BASE CASE ASSUMPTIONS, AND SYSTEM MODIFICATIONS (Cont'd)

	Summary of Recommendation	Base Case	System Modifications	Location of Cost Data
113	i) Condenser outlet temperatures should be maintained as high as possible without causing mortality of entrained fish ii) Where all entrained fish will be killed by physical or chemical effects condenser outlet temperatures should be as high as technically feasible iii) An annual temperature curve should be established which accounts for susceptible fish species	No rationale for the control of condenser outlet temperature based on the temperature susceptibility of entrained fish	Control of the condenser outlet temperature at the maximum possible temperature in accordance with an annual temperature curve which accounts for susceptible fish species	Negligible Cost Impact
114	The area occupied by the thermal plume should be less than 10 percent of near shore zone or less than 50 percent of distance across the water body	There is no provision for restricting the area of the thermal plume	a) A smaller plant with a once-through cooling system b) A recirculating cooling tower, pond or canal c) An offshore submerged discharge beyond the littoral zone	 G.3.2(a) G.3.2(d)
115	Once-through cooling water should be discharged beyond and directed away from the nearshore zone	Shoreline discharge of once-through cooling water	An offshore submerged discharge beyond the littoral zone	G.3.2(d)
116	Helper or supplementary cooling system should not be used with once-through cooling	Use of helper system	Alternatives to a helper system are: a) Standard once-through cooling system b) Recirculating cooling system	 No incremental cost G.3.2(a)

TABLE G.1 SUMMARY OF RECOMMENDATIONS, BASE CASE ASSUMPTIONS, AND SYSTEM MODIFICATIONS (Cont'd)

	Summary of Recommendation	Base Case	System Modifications	Location of Cost Data
201	For control of biofouling, corrosion, or scaling in recirculating cooling systems:			
	i) Chemicals should not be used unless demonstrated to be necessary or environmentally innocuous	Biofouling control by conventional chemical treatment	The use of mechanical biofouling control systems	G.3.3(a)
	ii) Asbestos based materials should not be used in cooling towers	Cooling towers contain asbestos based components	Use of non-asbestos based components in cooling towers	Negligible Cost Impact
	iii) Chromium additives should not be used for cooling pond systems	Additives contain chromium	Use of additives that are less harmful than chromium	G.3.3(c)
	iv) The use of chemical additives should be minimized	Chemical additives are used without major efforts to minimize their use	a) Dechlorination of recirculating cooling system blowdown b) Replacement of additives with less harmful compounds	G.3.3(b) G.3.3(c)
202	i) Evaporative recirculating cooling systems should operate at a minimum of 2 cycles of concentration	The absence of any specified minimum number of cycles of concentration.	Operation of evaporative recirculating cooling systems at a minimum of 2 cycles of concentration.	Negligible Cost Impact
	ii) Make up water for evaporative recirculating cooling systems should be added through the auxiliary coolers if practicable	Make-up water taken from forebay	Make-up water added through auxiliary coolers.	Negligible Cost Impact
203	Where auxiliary cooling water may become contaminated an intermediate closed recirculating loop system or other effective means of preventing contamination should be used	A once-through auxiliary cooling system with no intermediate recirculating loop	An auxiliary cooling system with an intermediate closed recirculating loop	G.3.3(e)
204	For ash collection, transport and disposal at coal fuelled stations, dry systems should be used for fly ash and recirculating systems for bottom ash unless wastewater discharges would be less using other systems	Once-through sluicing of fly ash and bottom ash and lagoon disposal	a) A combined wet recirculating and bottom ash transport and lagoon disposal system b) Dry fly ash/landfill disposal and recirculating bottom ash/lagoon disposal system c) Dry fly ash and dewatered bottom ash transport and disposal in landfill	G.3.3(f) G.3.3(f) G.3.3(f)

TABLE G.1 SUMMARY OF RECOMMENDATIONS, BASE CASE ASSUMPTIONS, AND SYSTEM MODIFICATIONS (Cont'd)

	Summary of Recommendation	Base Case	System Modifications	Location of Cost Data
205	Flue gas desulphurization systems for a fossil fuelled station should include a closed process water loop or equivalent (zero wastewater discharge) to the extent practicable	An open-loop wet limestone forced oxidation FGD system	A closed-loop wet limestone forced oxidation FGD system	G.3.3(g)
206	Water should be reused where practical	Little or no water reuse	Water reuse systems	Not Estimated
207	Disposal sites for ash, FGD wastes and station refuse should be developed in stages, contoured and reclaimed. Waste should have a physical and chemical stability suitable for reuse	No staged development contouring, or reclamation. FGD wastes are thixotropic (unstable) and unreclaimable	i) Contouring and reclamation of ash disposal sites ii) FGD sludge stabilization and site reclamation	G.3.3(f) G.3.3(h)
208 209	Containment of all contaminated liquid releases	No containment facilities	Containment facilities for all contaminated liquid releases	G.3.3(i)
210	Seepage to groundwater should be controlled by a barrier with a permeability equivalent to 1 m of material with a permeability ranging from 1 x 10^{-5} to 1 x 10^{-7} cm/s depending on the application	No special provision for seepage control	Natural clay, bentonite liners or synthetic liners of the required permeability under coal piles, ash and FGD sludge disposal sites, containment facilities and chemical and waste storage facilities	G.3.3(j)
211	Wastewaters released to the environment should not exceed the following standards: Iron 1.0 mg/L Chromium (total) 0.5 mg/L Chromium (Hexavalent) 0.05 mg/L Copper 0.5 mg/L Nickel 0.5 mg/L Zinc 0.5 mg/L Total Residual Chlorine 0.2 mg/L Oil & Grease 15.0 mg/L Total Suspended Solids 25.0 mg/L pH 6.5-9.5	No treatment for wastewaters which may exceed the limits of R211	Treatment based on oil separation, lime neutralization, and clarification for coal pile runoff, ash transport blowdown, boiler cleaning and boiler blowdown wastewaters and miscellaneous wastewaters exceeding limits of R211	G.3.3(k)

TABLE G.1 SUMMARY OF RECOMMENDATIONS, BASE CASE ASSUMPTIONS, AND SYSTEM MODIFICATIONS (Cont'd)

	Summary of Recommendation	Base Case	System Modifications	Location of Cost Data
212	Technological opportunities should be considered for the further control of radionuclide discharges from nuclear stations	No tritium removal system	Tritium removal system to limit tritium concentration in heavy water	G.3.3(m)
		No radioactive liquid waste treatment	Evaporator/Ion exchange active liquid waste treatment system	G.3.3(l)
213	Sanitary wastewaters should be segregated and given secondary biological treatment if not directed to a municipal treatment plant	Sanitary wastewaters are released untreated to the environment	Secondary biological sanitary waste treatment facilities	G.3.3(n)
301 to 309	Monitoring	Undefined	Facilities for monitoring once-through cooling water, wastewaters and groundwater	Negligible Cost Impact

to those recommended in this document. In choosing the base case assumptions, the conservative approach taken will lead to an overestimation of the costs associated with the recommendations.

Some of the base case assumptions detailed in Table G.1 have been modified in assessing overall cost implications in Section G.3.5. For example, it is assumed that the Western Canada coal-fired generating station will be built in a water-shortage area where once-through cooling will not be feasible. For this model, recirculating cooling is the appropriate base case assumption.

Some recommendations state that additional features "should be considered", that they be used if practicable or that alternatives may be used. By assuming that specific design features will result from the recommendations this analysis does not account for industry initiative in achieving environmental protection through lower cost alternatives.

G.3 Economic Implications of the Recommendations

G.3.1 Approach and Methodology for Estimating Costs

a) Approach. In many cases one design feature will mitigate the concerns associated with more than one recommendation. It may be impractical or impossible to isolate the incremental cost associated with each recommendation. Therefore, costs are based on design features and not on individual recommendations.

b) Economic and Technical Premises. A wide range of reported and estimated costs have been used in analyzing the cost implications of the recommendations. To provide a consistent basis of comparison, normalization of the widely divergent cost data has been attempted according to certain technical and economic premises.

i) All costs are expressed in 1983 Canadian dollars.

ii) Where necessary, U.S. dollars are converted to Canadian currency at an exchange rate of $1.00 Canadian (1983) = $0.80 U.S. (1983).

iii) Most of the data investigated were expressed in pre-1980 costs. In assessing these costs on a uniform basis, they are escalated or de-escalated at 12% per year compounded. This rate is derived from Canadian steam-electric power plant construction and maintenance prices for the period 1973 to 1983 inclusive (2). It is assumed that this rate is representative of the price increases associated with relevant pollution abatement technologies.

iv) Costs are expressed as average annual revenue requirements (AARR's) which are derived by converting annual costs (usually expressed in dollars or dollars/kW) to mills/kWh.

v) Total annual cost is comprised of net annual operating expenses plus annualized capital cost. Capital costs are annualized using a capital charge rate of 10% per year, which reflects the annual cost of a capital investment taking into account depreciation, insurance and taxes.

vi) Cost estimates from various sources assume plant and component lifetimes ranging from 30 to 35 years. Where necessary, a lifetime of 30 years has been assumed.

vii) Cost estimates from various sources assume base load plant capacity factors ranging from 40% to 80%. Where necessary, capacity factors of 60% for coal base load plants and 80% for nuclear base load plants have been assumed.

A sample calculation is as follows:

The literature indicates the following costs in $U.S. (1982) for a dry fly ash handling system in a 500-MW coal fired plant (3).

Capital Cost = $\$12.65 \times 10^6$
Annual Operating and Maintenance = 1.68×10^6 per year

At 10% Charge Rate:
Annual Capital Cost = $12.65 \times 10^6 \times 0.1$ = 1.27×10^6
Annual O&M Cost = $\underline{1.68 \times 10^6}$
Total Annual Cost = 2.95×10^6

Converting to $ Canadian (1983):
Total Annual Cost = $(2.95 \times 10^6/0.8) \times 1.12$ = 4.13×10^6 \$/a

$$\text{AARR} = \frac{4.13 \times 10^6 \text{ \$/a} \times 10^3 \text{ mills / \$}}{500 \text{ MW} \times 10^3 \text{ kW/MW} \times 8760 \text{ h/a} \times 60\% \text{ Capacity Factor}}$$

$$= 1.57 \text{ mills/kWh}$$

viii) For a number of system modifications cost estimates could not be readily obtained. In such cases and where costs were judged likely to be less than 0.01 mills/kWh, the costs were regarded as having a negligible cost impact (see table G.1). Although it is recognized that the costs for these systems themselves may not be negligible and may in fact be substantial, the impact on the total incremental costs for a new generating station (see tables G.23, G.24) will be negligible given the accuracy of the data.

c) Variability in Data. Cost data used in this analysis were taken from a large number of literature sources. Although the data were normalized according to the preceding premises, a wide variation in cost estimates remained. The following are the major factors believed responsible for variability in cost data.

i) Literature reported costs include projected and actual costs.
ii) Assumptions and factors taken into account are not always well documented in the literature. These may include indirect costs, such as interest during construction, contingencies, insurance, field expenses, legal expenses.
iii) The degree to which costs for pollution control systems have been isolated from costs for other systems is not always well documented.
iv) Power plant siting will determine land prices, topography, and soil characteristics. These will strongly influence costs relating to ash and sludge disposal.
v) Climate dictates costs relating to insulation, tracing and equipment enclosure.
vi) Coal used varies in ash content, heating value, and sulphur content.
vii) Degree of redundancy of equipment influences capital and operating costs.
viii) Cost of money, bidding conditions and financing arrangements vary in time and location.
ix) Economies of scale introduce inaccuracies when costs are expressed in mills/kWh.

Other attempts to define costs have found a high degree of variability in published data. CH_2M-Hill Ltd, in a study prepared for Environment Canada, found that even after rigorous analysis published cost data indicated cost variations of up to 324% for flue gas desulphurization equipment (4). **Because of the variability of data, costs in this analysis are expressed as ranges of probable costs and should be interpreted as order of magnitude estimates only.**

d) Use of Generic Models. In assessing the total costs of the recommendations, models have been used to define base case assumptions and a range of environmental control features appropriate to future Canadian steam electric power generation facilities. Each model is associated with a geographical area and reflects design considerations appropriate to that area. For example, once-through cooling is a reasonable base case assumption for a utility located in central Canada where fresh water is abundant, whereas in parts of western Canada where fresh water is in short supply, recirculating cooling would be a more reasonable base case assumption. It was intended that the analysis cover the range of probable economic impacts on new facilities - from the lowest cost to the highest cost. The choice of features and base case assumptions for individual models has been biased accordingly. It is emphasized that the models are generic in nature and do not indicate the combinations of features expected in a new generation facility.

G.3.2 Cost Estimates - Once-Through Cooling Recommendations. Costs for cooling water related systems will generally be higher for nuclear generating stations than for fossil-fuelled stations because cooling water flows at nuclear stations are approximately double those at fossil-fuelled stations. However, when expressed as average annual revenue requirements (AARR's, mills/kwh) the costs are expected to be similar because:

i) economies of scale indicate that cooling water related capital costs are not likely to double in going from a fossil-fuelled to a nuclear station of the same capacity; and
ii) in calculating AARR's capacity factors of 0.6 and 0.8 were used for fossil-fuelled and nuclear stations, respectively. This reduces the AARR's for nuclear stations relative to those for fossil-fuelled stations.

It has been determined using literature reported data (5) that the net effect of these factors is that the calculated AARR's for nuclear and fossil-fuelled generating stations are essentially equal. Therefore it has been assumed, unless otherwise indicated, that AARR's for cooling water related systems are appropriate to both fossil-fuelled and nuclear stations.

a) Recirculating Cooling System Utilizing Cooling Towers, Pond or Canal. These design features are potential means of mitigating the concerns associated with recommendations:

R101 - Cooling water withdrawal with respect to nearshore volume.
R102 - Minimization of water use for auxiliary cooling.
R114 - Influence of the thermal plume on the nearshore zone.

However, because recommendations R101 to R116 in Appendix D pertain to once-through cooling systems, it is assumed in this analysis that the adoption of recirculating cooling would answer all concerns expressed in Appendix D.

In determining the incremental AARR's for recirculating cooling systems the assumed base case was a once-through cooling water system. Although not specifically stated in the literature sources used, it was assumed that the base case assumptions involved shoreline or channel intakes or discharges.

The cost components that comprise the total system cost include capital investment, operation and maintenance, and energy penalty costs. The energy penalty costs usually take into account two factors. First, the reduction of plant capability below its firm power rating must be replaced by additional generating capacity (assuming a base load plant). The reductions in plant or turbine capacity appear to occur most frequently on hot summer days when the ambient temperature is greater than the design temperature, which creates a power reducing high turbine back pressure. Second, a penalty must also be assessed for the cooling system power and energy requirements, e.g., the power necessary to run pumps and fans.

The base case and incremental recirculating cooling system average annual revenue requirements are shown in Tables G.2 and G.3 for fossil fuelled and nuclear plants, respectively.

Where a number of AARR values for one system are available from one literature source, only the high and low values are shown. Generally, all the data show costs within the same order of magnitude for any one system. One exception is the information from reference 6 for a cooling pond. The variability of the data in this case probably results from the influence of local land costs and topography on individual cooling pond costs.

Generally, nuclear plants are expected to have higher costs for cooling systems because of the larger volumes of cooling water used. Although this trend can be seen in most of the data shown in Tables G.2 and G.3, there are cases where the reverse is true. This probably relates to economies of scale whereby a typically large nuclear plant compared to a small fossil-fuelled plant will have lower cooling system costs on a per MW basis.

Considering all the recirculating cooling system options shown in Tables G.2 and G.3, the data indicate that although the low range prices vary somewhat the only distinct trend is the higher cost of dry cooling systems.

b) Offshore Submerged Intake with a Velocity Cap. These design features are potential means of mitigating the concerns associated with recommendations:

R101 - Cooling water withdrawal with respect to nearshore volume.
R105 - Location of intake beyond the littoral zone.
R107 - Intake designed to minimize entrainment.
R108 - Design of shoreline intakes.

TABLE G.2 BASE CASE AND INCREMENTAL COOLING SYSTEM AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR FOSSIL FUELLED PLANTS

Source	7	6a	6b	6c
Once-Through Cooling (Base Case) AARR	1.19		0.67	0.79
Incremental AARR's				
Cooling Pond	2.56	0.04-0.27	0.23	
Spray Canal	1.48	0.23-0.31		
Towers:				
Wet Natural Draft	1.32-1.65	0.62-1.01		1.62
Wet Fan Assisted	1.32-1.92			
Wet Mechanical Draft	1.12-1.72	0.19-0.54	0.36	0.74
Dry Natural Draft		1.98-5.51		
Dry Mechanical Draft	7.12-8.59	2.14-4.39		
40% Wet/Dry	3.28-3.92			

Notes: Data from reference 6 are separated into 6a, 6b, 6c according to the original source of the data. Data from 6b and 6c included capital cost only. Operation and maintenance and energy penalty costs were estimated at 15% of capital cost.

As described in Subsection D.1, a typical once-through cooling system is comprised of an intake, forebay, screens, pumps, condenser, and outfall. Basically, there are three types of once-through cooling water system intakes: shoreline, channel, and offshore submerged intake. Assuming either shoreline or channel intakes as representative of a base case, Table G.4 indicates the incremental AARR's associated with offshore submerged intakes.

Intake system costs will generally be higher for nuclear generating stations than for fossil-fuelled stations because of the higher volumes of cooling water required. Reference 5 does not differentiate between costs for nuclear and fossil-fuelled station intakes. The AARR's from reference 8 apply to a nuclear station but these costs are within the range of AARR's derived from reference 5. It is therefore assumed that the difference in cost between nuclear and fossil-fuelled station intake systems is within the accuracy of the data and thus no differentiation can be made in this analysis.

TABLE G.3 BASE CASE AND INCREMENTAL COOLING SYSTEM AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR NUCLEAR PLANTS

Source	7	6a	6b	6c
Once-Through Cooling (Base Case) AARR	1.59		0.50	1.08
Incremental AARR's				
Cooling Pond	2.79	0.08-0.66	0.17	
Spray Canal	1.49			
Towers:				
Wet Natural Draft	1.19-1.60	0.66-1.67		0.80
Wet Fan Assisted	1.25-1.69			
Wet Mechanical Draft	1.12-2.46	0.08-1.44	0.27	0.38
Dry Natural Draft		3.57-6.1		
Dry Mechanical Draft	9.6-11.8	3.38-5.32		
40% Wet/Dry	4.05-6.23			

Notes: Data from reference 6 are separated into 6a, 6b, 6c according to the original source of the data. Data from 6b and 6c included capital cost only. Operation and maintenance and energy penalty costs were estimated at 15% of capital cost.

c) Fish Bypass Facilities. The relevant recommendation is:

R109 - Provision of a fish bypass and return system.

As described in Appendix D, there are a number of options to prevent fish from entering the cooling water pumps once the fish have entered the intake. These options include bucket additions and bypass in combination with vertical travelling screens, horizontal travelling screens to divert fish to a bypass, and louvre arrays combined with flush mounted fine mesh screens. For this analysis the base case assumption is that there is no fish bypass system.

Table G.5 shows the AARR's associated with fish bypass systems for selected Ontario steam electric generating stations (9). The fish bypass system descriptions indicate that components common to each system are fish collection buckets, transport troughs, and discharge pumps.

TABLE G.4 ONCE-THROUGH COOLING SYSTEM INTAKE AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh 1983 Canadian $)

	Base Case		Offshore Submerged		
Source	Type	AARR	Length (m)	AARR	Incremental AARR
5	Shoreline	0.093	975	0.278	0.185
5	Channel	0.232	975	0.278	0.046
8*	Channel	0.001	1000	0.076	0.075
		0.001	1310	0.102	0.101
		0.007	1450	0.111	0.104

* Cost data from reference 8 do not include costs for common parts of the channel and submerged intake systems. Thus the base case and submerged intake AARR's appear very low compared to those from reference 5, but the incremental AARR's remain valid.

The wide variation in AARR's is probably the result of the type of bypass facility and site specific geographical and physical constraints. For example, the highest AARR relates to an addition to the existing facility at the relatively small Thunder Bay generating station. AARR's for bypass facilities at new and much larger stations are relatively low.

d) Offshore Submerged Discharge. The relevant recommendations are:

R114 - Influence of thermal plume on the nearshore zone.
R115 - Location of outfall beyond the nearshore zone.

For this analysis the base case is assumed to be a shoreline discharge. The information in Table G.6 was derived from cost data for the Darlington nuclear generating station in Ontario. Although differential energy and capability costs were included in the data it is not clear how these were calculated. No operating and maintenance costs were given.

e) Mechanical Biofouling Control System. The relevant recommendations are:

R111 - Control of biofouling.
R112 - Control of scaling and silting.

TABLE G.5 SELECTED ONTARIO GENERATING STATION FISH BYPASS SYSTEM AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) (9)

Station	Type	Capacity (MW)	Fish Bypass System Description	AARR
Darlington	nuclear	3400	Angled bar racks guide healthy fish from forebay to a quiescent zone and fish pumphouse. Two fish pumps discharge fish to lake.	0.003
Bruce B	nuclear	2928	Fish buckets on the vertical travelling screens pick up fish and deposit them in a fish trough which deposits the fish by trough to a sump. The sump is lined with a basket which is periodically lifted and emptied to a trailer for transport to the lake.	0.003
Atikokan	coal	800	Angled bar screens guide fish from forebay to a holding area fitted with a fish elevator. A basket is elevated periodically to transfer fish to a trailer for transport to the lake.	0.023
Thunder Bay	coal	300	Fish in the screenwall are attracted by lights to a sump to be pumped to the river. Fish which do not move to the quiescent zone will be picked up by buckets and deposited by trough to a sump.	0.089

TABLE G.6 COOLING SYSTEM OUTFALL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian)

Reference	Base Case (Shoreline) AARR	Length (m)	Diffuser	AARR	Offshore Submerged Incremental AARR
10	0.62	804	Yes	0.82	0.20
10	0.62	1608	Yes	0.91	0.29
10	0.62	1608	No	0.80	0.18
10	0.62	3216	No	0.97	0.35
11		Not Specified	Yes		0.05-0.10

Note: The data from reference 10 pertain to a 4 x 850 MW station and refer to capital and differential energy and capability costs for lined tunnels.

The data from reference 11 refer to capital, operating and energy costs for a variety tunnel lengths and plant capacities.

A potential means of controlling biofouling and scaling or silting in condenser tubes is the use of on-line mechanical systems such as the Amertap and ATCS systems described in Section D.5. An advantage of such systems is that they avoid the use of chemicals which could cause environmental damage. In this analysis the assumed base case is a conventional chemical treatment system for biofouling control.

Table G.7 indicates Amertap and ATCS system capital operating and maintenance costs derived from a U.S. EPA development document (6, pp. 270-277). The base case costs quoted relate to conventional chemical treatment for an evaporative recirculating cooling system using mechanical draft cooling towers.

f) Chlorine Minimization and Dechlorination Systems. The relevant recommendation is:

R111 - Chlorine minimization.

As noted in Subsection D.5, where mechanical cleaning is not effective or feasible, chlorine is expected to remain the most common biocide. In controlling total residual chlorine (TRC), several technologies are currently available (12).

A chlorine minimization program may comprise existing chlorination facility upgrading, a study of the effects of various chlorine minimization strategies and implementation of effective procedures. Dechlorination involves the addition of a

TABLE G.7 ON-LINE MECHANICAL BIOFOULING CONTROL SYSTEM AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian)

	Base Case Chemical Treatment AARR	Mechanical System AARR	Incremental AARR
Amertap	0.016	0.043	0.027
ATCS	0.016	0.037	0.021

Reference: 6, pp. 270-277

chemical reducing agent to the cooling water for reduction of chlorine to a non-toxic chloride.

For this analysis the assumed base case is a standard chlorination system comprising a chlorinator, injector, diffuser and a chlorine residual analyzer/recorder, and no provision for dechlorination.

Chlorine minimization and dechlorination AARR's derived from two recent USEPA documents (12, pp. 421-426; 13, p. III-8) are 0.005 and 0.038 mills/kWh, respectively (1983 $ Canadian).

G.3.3 Cost Estimates - Wastewater Recommendations

a) Mechanical Biofouling Control for Recirculating Cooling System. The relevant recommendation is:

R201(i) Non-chemical methods for control of biofouling, corrosion, and/or scaling.

In a recirculating cooling system one means of minimizing wastewater production and reducing wastewater treatment costs is on-line mechanical cleaning systems. For this analysis it is assumed that the discussion and costing of such systems in Section G.3.2 (e) is applicable to recirculating cooling systems.

b) Dechlorination of Recirculating Cooling Blowdown. The relevant recommendation is:

R201(iv) Minimization of chemical additives.

A U.S. EPA development document (12) indicates that chlorine minimization is impractical for recirculating cooling systems. Where chlorine is used to prevent biofouling in recirculating cooling systems dechlorination is the preferred technology for reducing the toxicity of blowdown wastewaters. The dechlorination AARR derived from two recent U.S. EPA documents, (12, p. 425; 13, p. III-8) is 0.005 mills/kwh (1983 $ Canadian).

c) Replacement of Corrosion, Scaling, and Silting Control Chemicals. The relevant recommendation is:

R201(iv) Minimization of chemical additives.

Where the use of chemicals for corrosion, scaling and silting control is judged necessary it may be possible to replace chemicals containing zinc, chromate, and other compounds of known toxicity with less harmful chemicals.

Two recent U.S. EPA documents (12, 13) contain analyses of the cost of replacing chemicals containing priority pollutants with ones which do not contain priority pollutants for control of corrosion, scaling and silting in recirculating cooling systems. The analyses do not specify which chemicals are being considered and therefore it is only assumed here that the chemicals would be appropriate. The costs derived from the above references range from 0.002 to 0.014 mills/kwh (1983 $ Canadian).

d) Operation of Recirculating Cooling Systems at a Minimum of Two Cycles of Concentration. The relevant recommendation is:

R202 Recirculating cooling.

In R202 a minimum of two cycles of concentration are specified for the operation of a recirculating cooling system. For this analysis it is assumed that the cost data given in Section G.3.2 (a) are relevant to recirculating cooling systems run in this manner.

e) Intermediate Closed Recirculating Loop Auxiliary Cooling. The relevant recommendation is:

R203 All auxiliary cooling systems in which the auxiliary cooling water is potentially contaminated should be recirculating loop systems.

For this analysis the assumed base case is a once-through auxiliary cooling system.

Capital and operating cost data for an intermediate closed recirculating loop auxiliary cooling system are difficult to obtain. The approach used was to base costs on those for main cooling system condensers. Appendix D indicates that auxiliary cooling water represents approximately 5% of the total fossil fuel station intake and 12% of the total nuclear station intake. Using these numbers as scaling factors and published condenser capital cost data (14, pp. 131, 167, 211), the derived auxiliary cooling system AARR's for fossil fuelled and nuclear plants are 0.01 and 0.024 mills/kwh, respectively (1983 $ Canadian). Reference 14 states that yearly operation and maintenance costs for condensers are less than 1% of the capital cost; therefore, these costs were disregarded. However, because a complete recirculating loop auxiliary cooling system will entail additional capital and operating costs for piping, pumps, etc., the above AARR's must be considered as underestimations.

Estimated capital costs for recirculating loop auxiliary cooling systems at the Darlington nuclear generating station indicate an AARR of approximately 0.081 mills/kWh (1983 $ Canadian) although this also assumes negligible O & M costs and does not take into account costs relating to possible de-rating in warm weather (15).

f) Recirculating or Dry Ash Collection, Transport and Disposal Systems. The relevant recommendation is:

R204 Limiting the wastewater produced by ash transport systems.

For this analysis the assumed base case is once-through sluicing of fly ash and bottom ash to a lagoon ash disposal system. It should be noted that many recently built plants have incorporated recirculating or dry ash transport and disposal systems because these systems have the following advantages:

- less contaminated water to be treated prior to discharge;
- the systems require less space;
- dry systems reduce scaling and abrasion problems;
- dry systems allow for utilization of fly ash;
- in some areas limited water supplies may preclude once-through systems.

Because many utilities may adopt dry or recirculating systems for the above reasons the data shown in this analysis are probably an overestimation of the costs associated with R204.

System options considered for dry or recirculating ash transport and disposal include:

i) separate or combined wet recirculating fly ash and bottom ash transport and lagoon disposal with either limited blowdown or sidestream softening to control scaling;

ii) dry fly ash transport and landfill with wet recirculating bottom ash transport and lagoon disposal;

iii) dry fly ash transport and landfill with dewatering of bottom ash and subsequent landfill.

Components of wet ash systems include collection hoppers, vacuum or pressure conveyance systems, ash and water mixing systems, air separators, slurry pumps, piping and sluiceways, lagoons, overflow devices, return water piping, and hydrobin separators for bottom ash dewatering.

Components of dry ash systems include ash collection hoppers, storage silos, vacuum or pressure conveyance systems, haulage equipment and landfill maintenance equipment.

Costs (AARR's) for base case and incremental systems are given in Table G.8. As noted in the table some estimates include costs for such items as electrostatic precipitators, impermeable lagoon liners and lagoon discharge treatment systems. Although these costs are outside the scope of this analysis and are considered elsewhere in this section, it was not possible to isolate them from the available cost information. The effect of including these costs would be an overestimation of the costs associated with R204.

The cost data shown in Figure G.8 are remarkably consistent. The negative incremental AARR shown for the dry fly ash/dewatered bottom ash system probably relates to the inclusion of clay lagoon liner and p^H control costs in the base case cost data. However, in cases where land adjacent to a power plant is very expensive or unsuitable for lagoon construction, or where water is in short supply, dry ash landfill at a more remote site may in fact be the least cost alternative.

g) Closed Process Water Loop for Flue Gas Desulphurization (FGD) Systems. The relevant recommendation is:

R205 Closed process water loop for FGD systems.

The costs and in fact the applicability of this recommendation depend on the type and design of the FGD system installed. Spray drier systems have no process water discharge and therefore there is no cost for closing the loop for these systems. For limestone wet scrubbing systems, which are most commonly used to date, the cost of closing the loop would depend on the type of coal burned, the degree of oxidation of the FGD solids and the solids disposal option chosen. It has been reported that the greatest

TABLE G.8 ASH TRANSPORT AND DISPOSAL SYSTEM AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian)

Base Case Once-Through Sluicing of Fly & Bottom Ash		Combined Wet Recirculating Ash Transport & Disposal		Fly Ash to Land-fill, Recirculating Bottom Ash to Lagoon		Dry Fly Ash and Dewatered Bottom Ash to Landfill	
Source	AARR	AARR	Incremental	AARR	Incremental	AARR	Incremental
16	1.02	1.06	0.04	1.58	0.56	1.58	0.56
17		1.24				1.64	
3	1.84	1.97	0.13			1.57	-0.27

Sources: 16 - Popular River Study - Based on 600 MW Station
Costs include electrostatic precipitator and excavation and compaction of till for lagoon bottom permeability of 1.5×10^{-5} cm/sec.
Dry ash landfill in mine.

17 - Sundance Power Station - Based on 750 MW Station
Costs include lagoon reclamation.

3 - Tennessee Valley Authority - Based on 500 MW plant
Costs include clay liners for ponds and/or clay base for landfill, runoff control, reclamation.
Includes p^H control for once-through discharge and lime-soda softening for recirculation system.

difficulties in closing the loop will probably exist in forced oxidation systems (18, 19). For this analysis the assumed base case is a wet limestone forced oxidation system in which a blowdown of process water is discharged to the environment without treatment (an open-loop system). This blowdown is assumed to maintain process liquor chloride concentration at 1000 mg/L for corrosion control.

Incremental costs of closing the process loop for various wet limestone forced oxidation system options are given in Table G.9 (19). The analysis includes the cost of nickel-based alloy cladding in areas where this would be necessary because of the increased chloride concentrations in closed-loop systems. Costs of solid nickel-based alloy construction (for example 6 mm. plate) would be higher. Solids disposal costs are also included in the analysis.

The incremental cost of option 3 in Table G.9 is nearly 3 times higher than the incremental costs of other options for the Nova Scotia case and much higher than the incremental costs of other options for the Ontario case. This is a result of the high cost of treating the relatively large volumes of blowdown required to maintain an equilibrium chloride level of 1000 mg/L. Costs for option 3 will not be considered for further analyses in this document.

h) Flue Gas Desulphurization (FGD) Sludge Stabilization. The relevant recommendation is:

R207 Disposal of ash, FGD wastes, and station refuse.

For this analysis the assumed base case involves the lack of staged development, contouring and reclamation for ash disposal sites and the operation of a natural oxidation wet lime or limestone (non-regenerative) FGD system in which scrubber effluent is thickened to 30-40% solids before being sent to a settling pond. The FGD waste settles to a physically unstable, thixotropic sludge which would preclude reclamation and reuse of the site.

Methods of mitigating the concerns expressed in R 207 include the staged development, contouring and reclamation of ash disposal sites. Costs for reclamation of ash disposal sites are included in ash disposal data in part (f) of this section (Table G.8, References 3, 17) and are not repeated here. It is assumed that costs for contouring are included in these data and that costs for staged development are negligible.

TABLE G.9 CLOSED-LOOP FGD SYSTEM INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) (19)

Location (Coal Used), Disposal Option	AARR Open-loop Base Case	Incremental AARR's Closed-loop Systems Option 1	Option 2	Option 3
Nova Scotia, Dry Stacking	16.18	1.05	1.14	2.84
Nova Scotia, Wet Stacking	14.94	1.09	1.23	2.96
Ontario, Dry Stacking	15.12	1.10	1.17	1.61
Ontario, Wet Stacking	14.25	1.11	1.18	1.61

Base Case: Open-loop forced oxidation FGD system with equilibrium chloride concentration maintained at 1,000 mg/L via a blowdown of process liquor.

Option 1: Closed-loop forced oxidation system with no blowdown

a equilibrium chloride = 43,950 mg/L
b equilibrium chloride = 107,240 mg/L
c equilibrium chloride = 48,130 mg/L
d equilibrium chloride = 31,220 mg/L

Option 2: Closed-loop forced oxidation FGD system with equilibrium chloride concentration maintained at 27,000 mg/L via a blowdown which is treated by mechanical evaporation and reused.

Option 3: Closed-loop forced oxidation FGD system with equilibrium chloride concentration maintained at 1,000 mg/L via a blowdown which is treated by mechanical evaporation and reused.

Under the base case assumptions of this analysis costs for FGD sludge stabilization are expected to be the major costs of mitigating the concerns expressed in recommendation 207. Options considered for FGD sludge stabilization include:

i) Sludge/Flyash Blending Process,

The 30% solids sludge from the thickener is dewatered to 60% solids using a rotary drum filter. Dry fly ash is blended with the sludge to produce a soil-like material which is landfilled using conventional equipment.

ii) Gypsum Process,

Sulphite scrubbing slurry is oxidized via a forced air sparging system to produce a high sulphate sludge. It is subsequently dewatered via a thickener and a rotary drum filter to an 80% solids material which is landfilled in the same manner as the sludge/fly ash mixture.

iii) IUCS Process,

FGD sludge is dewatered to 60% solids via a thickener and rotary drum filter and then stabilized by adding fly ash and IUCS additive lime. It is then landfilled as in the above processes.

iv) Dravo Process,

FGD sludge is dewatered to 35% solids via a thickener and treated with additives (Calcilox and Thiosorbic lime). The treated sludge is pumped to a clay-lined 15-30 day capacity curing pond. After settling and curing the material is taken from the pond and landfilled as for the above processes.

v) Chemfix Process.

FGD sludge is dewatered to 60% solids via a thickener and rotary drum filter and treated with additives (sodium silicate and portland cement). The stabilized sludge is then landfilled as for the above processes.

All of the above processes result in a stabilized FGD sludge. The following analysis includes costs for compacting and contouring the landfill and covering it with soil. It is assumed that these costs are a major component of reclamation costs for the disposal site.

Although a variety of cost data is available concerning FGD sludge disposal and fixation much of the literature is based on two EPA sponsored reports (20, 21). These reports, by the same authors, are very well documented and based on the same technical and economic premises. Data from these reports, adjusted to the premises of this analysis, are shown in Table G.10.

Costs for FGD scrubbers, electrostatic precipitators and impermeable pond or landfill liners are not included in Table G.9. The costs of impermeable liners are considered in Section G.3.3 (j) concerning R210. Table G.10 indicates that the gypsum process would be the least expensive alternative. Another report, although not based on the same economic and technical premises, indicated that a forced oxidation/gypsum stacking option would be less expensive than the gypsum landfill option shown in Table G.10 and possibly less expensive than the base case of untreated ponding (22). If the sludge/fly ash blending process were used, the costs for separate disposal of fly ash would be reduced. It should be noted that the base case for this analysis (a natural oxidation FGD system) is different from that of the previous analysis concerning closed-loop forced oxidation FGD systems. Thus, the costs presented in Tables G.9 and G.10 could not be applied additively to the same FGD systems. Because forced oxidation systems produce a waste product (gypsum) which is assumed to be physically stable, sludge stabilization costs

TABLE G.10 FLUE GAS DESULPHURIZATION SLUDGE STABILIZATION AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian)

Sulphur Content of Coal %	Untreated Ponding (Base Case) AARR	Sludge/Fly Ash Blending Incremental AARR	Gypsum Process Incremental AARR	IUCS Process Incremental AARR	Dravo Process Incremental AARR	Chemfix Process Incremental AARR
2	0.76	0.86	0.12	1.26	1.07	1.31
3.5	1.09	0.81	0.17	1.25	1.42	1.51
5	1.37	0.77	0.11	1.42	1.81	1.86

References: 20, 21

Note: The data from reference 21 relating to the gypsum process have been revised to estimate the cost of disposing of gypsum only (no fly ash).

would not be applicable. For natural oxidation systems, costs in Table G.10 (with the exception of the gypsum process) probably represent both the cost of sludge stabilization and closing the loop because the sludge/fly ash blending process and the three chemical fixation processes would probably allow sufficient blowdown of process liquor, in the form of occluded water, to close the process loop. Therefore, for further analyses in this document the costs of meeting the closed-loop (R205) and sludge stabilization (R207) requirements will be assumed to be in the range of either 1.05 - 1.23 mills/kWh for forced oxidation systems (Table G.9) or 0.77 - 1.86 mills/kWh for natural oxidation systems (Table G.10, gypsum process excluded).

i) Wastewater Collection and Containment Facilities. The relevant recommendations are:

R208	Containment of liquid releases
R209	Capacity of collection and containment facilities.

For this analysis the assumed base case is the absence of containment facilities for switchyard, coal pile, and yard drainage. The analysis estimates costs for separate dykes around the switchyard and coal piles and a dyked area to contain yard drainage for coal fired generating stations. Because the costs for these facilities are highly site-specific the following simplifying assumptions have been made.

i) The switchyard and coal pile occupy 10 ha and 18 ha, respectively, and the dykes around them are 0.9 m high.

ii) The dyked area for containment of yard drainage is designed to contain the runoff from a 100 ha yard during a 24-hour, 100-year rainfall event (23).

iii) Dykes are constructed of imported fill at a cost of $\$10/m^3$ for material and placement.

iv) The cost of land for the containment area is not included in the calculation.

v) The cost of an impermeable liner (1 m where kp = 1×10^{-7} cm/s) for the coal pile is considered in the following section on seepage control. It is assumed that the native soils in the switch yard and yard drainage confinement areas have a permeability less than 1×10^{-5} cm/s and therefore no liner is required.

vi) It is assumed that all power generation stations will have dykes around the tank farm and the costs of these are therefore not considered incremental costs.

vii) It is assumed that the costs for separate containment of hazardous or incompatible chemicals are highly site-specific and negligible compared to the other containment costs considered in this analysis.

viii) Outdoor wastewater treatment of holding facilities would be separate from the yard drain confinement area. The additional cost of building the wastewater facility to accommodate a 24-hour, 100-year rainfall event would be negligible.

ix) Stormwater containment at FGD and ash disposal areas is included in the costs indicated for those facilities.

The costs of containment facilities are estimated as follows:

Facility	Area (ha)	Cost of Dyke 0.9 m High (1983 $ Canadian)
Switchyard	10	$ 30,700
Coal Pile	18	$ 41,200
Yard Drainage Containment	16	$ 38,900
(Yard area = 100 ha)		
Total		$110,800

Max AARR = 0.0021 mills/kWh (1983 $ Canadian)

The above figures represent the maximum average annual revenue requirement. Where containment dykes can be constructed during the initial site preparation activities of clearing, grubbing and contouring, the incremental AARR would be negligible.

No containment would be needed for coal piles at nuclear facilities and the need for yard drainage containment would probably be greatly reduced because of the lack of fugitive emissions and possible leaks from coal and ash handling systems. It is therefore assumed that the cost of containment facilities at nuclear stations would be negligible (i.e., AARR <0.001 mills/kWh).

j) Seepage Control. The relevant recommendation is:

R210 Achievement of specified permeabilities beneath coal piles, ash disposal sites, FGD sludge disposal sites, and other facilities.

For this analysis the assumed base case is the absence of any special provision for the control of contaminated seepage from plant facilities. Because certain naturally occurring soils have permeabilities equal to or lower than those specified in R210, the cost of seepage control for some generating stations would be negligible.

For this analysis it is assumed that natural bentonite incorporated into most soils at rates of 8.2 - 25 kg/m^2 will provide permeabilities within the range specified in R210. Total installed costs per m^2 of such a liner, based on the application of Wilcox, Saskatchewan bentonite at the Key Lake Saskatchewan uranium mine, are shown in Table G.11. (24) Costs are given for several provinces to indicate the effect of transportation costs (bentonite) on the total installed cost.

The costs of natural clay liners are highly site-specific and are therefore not estimated here.

The Poplar River report (16) estimates the cost of a synthetic liner at \$6.22 - \$8.29/m^2 (1983 \$ Canadian) which is within the range of bentonite liner costs in Table G.11. Generally, synthetic liners appear to be more expensive than natural clay or bentonite. Further seepage control costs will be based on the bentonite liner costs in Table G.11.

TABLE G.11 TOTAL INSTALLED COSTS (1983 \$ Canadian) OF BENTONITE LINERS PER m^2 (24)

	Total Installed Cost (\$/m^2)	
	Applied Rate 8.2 kg/m^2	Applied Rate 25 kg/m^2
B.C.	5.90	8.11
Alberta	5.62	7.24
Sask.	5.55	7.02
Manitoba	5.52	6.95
Ontario	5.93	8.16
Quebec	5.94	8.23

At a coal fired power generation facility the majority of the seepage control costs will be related to liners for coal piles and ash and FGD sludge disposal areas. The total liner area required for these facilities will depend on the quantity of coal stored, coal energy, ash and sulphur content, the bulk density of ash and FGD sludge and the geometry of the coal storage and ash and FGD sludge disposal areas. The average revenue requirements (AARR's) will therefore be highly site-specific.

Possible ranges of AARR's for seepage control are given in Table G.12. These are based on the lowest and highest probable liner areas calculated from combinations of the above parameters for a 1000-MW plant. Because the highest cost AARR's combine all the "worst case" assumptions they are almost certainly an overestimation. The least cost AARR's could also be considered overestimations in cases where the local soils are relatively impermeable and the costs of seepage control are negligible. The range of costs in Table G.12 is presented only for comparison with AARR's for other design features. More realistic AARR's are calculated for each of the models in Section G.3.5.

TABLE G.12 AVERAGE ANNUAL REVENUE REQUIREMENTS (1983 $ Canadian) FOR MINIMUM AND MAXIMUM COST SEEPAGE CONTROL SCENARIOS AT 1000-MW COAL FIRED POWER GENERATION FACILITIES

	Total Landfill Area	
Parameter	Minimum	Maximum
Coal Energy Content (MJ/kg)	28.0	14.0
Coal Sulphur Content (%)	2.0	0.4
Coal Ash Content (%)	10.0	30.0
Ash Disposal Type	Landfill	Lagoon
Ash Disposal Depth (m)	23.0	6.0
Ash Bulk Density (g/cm^3)	1.44	0.72
FGD Sludge Disposal Type	Landfill	Lagoon
FGD Sludge Disposal Depth (m)	23.0	6.0
FGD Sludge Density (g/cm^3)	0.86	0.56
Ash Disposal Area (m^2)	1.6×10^5	8.3×10^6
FGD Sludge Disposal Area (m^2)	1.9×10^5	2.2×10^5
Coal Pile Area (m^2)	1.0×10^4	9.5×10^4
Total Liner Area (m^2)	3.6×10^5	8.62×10^6
Liner Cost ($/m^2)	5.52	8.23
Total Cost ($ Can. 1983)	2.0×10^6	7.09×10^7
AARR (mills/kWh)	0.04	1.34

Coal characteristics, and ash and FGD sludge disposal areas were derived from Tables 1 and 13, Reference (25).

k) Wastewater Treatment. The relevant recommendation is:

R211 Contaminant concentration limits in wastewater

For this analysis it is assumed that there are no wastewater treatment facilities and that the following discharges from a coal-fired plant with once-through cooling are in excess of those specified in R211:

- coal pile runoff,
- ash transport water blowdown,
- boiler cleaning wastewaters,
- water treatment wastewaters, and
- floor and laboratory drains.

For nuclear stations, the first two wastewater sources would not apply (Radioactive wastewaters are discussed in sections l) and m) below).

Treatment of these streams by equalization, oil separation, neutralization, chemical (lime) precipitation and clarification is common and will generally meet the effluent limitations of R211. Polyelectrolyte flocculating agents and filtration may be used to improve treatment where necessary.

For this analysis it is assumed that chlorine minimization is practiced and that the wastewaters do not contain any chromium additives, thus eliminating the need for chlorine and chromium removal processes.

Costs (AARR's) for installing and operating treatment processes for the above wastewaters are shown in Table G.13. The costs range from 0.274 to 0.297 mills/kWh for coal fired stations and 0.13 mills/kWh for nuclear stations. The lower wastewater treatment costs given in the literature for nuclear stations relate in part to the absence of coal pile runoff and ash transport water treatment facilities.

Costs will vary depending on the wastewater volumes and characteristics at specific plants. Costs for coal pile runoff treatment will be very low at plants where coal piles are small (mine mouth plants) and where net annual precipitation is low. Costs for treatment of ash transport wastewaters will be eliminated where dry or total recirculation ash transport systems are used. In many cases the waste streams used in this analysis will meet the criteria of R211 without "treatment".

Costs for alternate treatment processes for coal-fired plant wastewaters are also given in Table G.13. Treatment of boiler blowdown, floor and laboratory drains, and water treatment wastewaters by vapour compression evaporation (VCE) would cost approximately 0.38 mills/kWh. Although this cost was quoted for a coal-fired generating

TABLE G.13 WASTEWATER TREATMENT AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR PLANTS WITH ONCE-THROUGH COOLING SYSTEMS

			AARR (mills/kWh)	
Waste Stream	Treatment Process/System	Ref.	Coal-Fired	Nuclear
Coal Pile Runoff	Runoff confinement, lime neutralization polyelectrolyte addition, settling	6,26 12	0.004 - 0.017 0.019 - 0.027	N/A
Ash Transport Water Blowdown	Softening for 10% of recirculating bottom ash transport stream	12	0.05	N/A
Boiler Cleaning Boiler Blowdown Floor Drain and Water Treatment Wastewaters	Equalization, oil separation, lime softening, flocculation, clarification, filtration	6	0.22	0.13
Total of the above			0.274 - 0.297	0.13
Boiler Blowdown Floor and Lab Drain, and Water Treatment Wastewaters	Vapour compression evaporation with spray drying of brine	12	0.38	
All Plant Wastewaters Except cooling but Including FGD Wastewaters	Equalization, oil separation, neutralization, coagulation, sedimentation, filtration, COD removal, sludge thickening	27	0.78 - 1.25	

station, treatment costs for boiler blowdown and water treatment wastewaters at a nuclear station would probably be similar (floor and laboratory drains in a nuclear station could contain radioactive contamination and would therefore be handled separately). Although a costly method of handling these wastes, VCE has the advantages of dissolved solids removal and improved metals and suspended solids removal. This would result in a high quality water suitable for re-use within the plant.

An OECD report from Japan describes a comprehensive treatment system for a coal-fired generating station which includes COD removal and treatment of FGD wastewater at a reported cost of 0.78 - 1.25 mills/kWh (27).

Generating stations which use recirculating (cooling tower) cooling systems may require treatment for the blowdown from these systems to meet the effluent limitations of R211. Generallv, a treatment system based on chemical precipitation will provide adequate removal of metals and suspended solids. Costs (AARR's) for a chemical precipitation system for treatment of cooling tower blowdown are given in Table G.14. Because these costs are based on a process that includes chromate reduction, treatment system costs for plants that do not use chromium additives will be lower.

A higher degree of treatment, including dissolved solids removal, can be provided by vapour compression evaporation (VCE), vertical tube foaming evaporation (VTFE) or reverse osmosis (RO) systems. Although the effluents from these processes are normally of higher quality than specified in R211, these processes have the advantage that their effluents can be reused in plant processes requiring high quality water. This is particularly appropriate in water short areas or where intake water quality is much poorer than the effluents from these processes. Costs (AARR's) for VCE, vertical tube foaming evaporation (VTFE) and RO systems are shown in Table G.14.

Incorporation of VCE and/or RO processes into a zero dicharge system at a coal-fired station involves costs of 0.70 - 3.54 mills/kWh as shown in Table G.14.

l) Evaporator/Ion Exchange Radioactive Liquid Waste Treatment System. The relevant recommendation is:

R212 Consideration of radioactive wastewater treatment systems.

For this analysis the assumed base case is the absence of a radioactive liquid waste treatment system for a nuclear station. Although R212 contains no radioactivity criteria for wastewater discharges, an evaporator/ion exchange system is costed here because it represents state of the art environmental control for radioactive wastewaters and is therefore analogous to some of the systems costed for coal-fired stations. The

TABLE G.14 WASTEWATER TREATMENT AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR PLANTS WITH RECIRCULATING COOLING SYSTEMS

Waste Stream	Treatment Process/System	Ref.	AARR (mills/kWh)	
			Coal-Fired	Nuclear*
Cooling Tower Blowdown	Chemical Precipitation, flocculation clarification, filtration (chromate reduction)	6	0.44	0.67
	Vapour compression evaporation (VCE)	12	1.51	2.27
	Vapour compression evaporation (VCE)	28	2.36	3.54
	Vertical tube foaming evaporation (VTFE)	28	1.33	2.00
	Reverse osmosis (RO)	28	1.38	2.07
All Wastes (Zero Discharge)	Central treatment concept - oil separation, lime-soda softening, precipitation, brine concentration for cooling tower and ash transport blowdowns	6	0.70	
All Wastes (Zero Discharge)	Highly complex system incorporating neutralization, settling, lime-soda softening, reverse osmosis, vapour compression evaporation, mechanical dewatering of waste brine	29	3.54	

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* AARR's for nuclear generating stations were estimated by assuming that blowdown volumes would be 2x those for coal-fired stations and that treatment costs (a large component of which are energy costs) would therefore be approximately 2x higher.

rationale for costing an evaporator/ion exchange system instead of other treatment systems available is also based on the following:

i) An evaporator/ion exchange system is capable of a decontamination factor of 10^6, making it one of the most effective systems in terms of effluent quality. It results in essentially "zero discharge" of non-volatile radionuclides (30).

ii) For the expected liquid waste volumes of 25 000 m^3/a for a 1000-MW station the costs of operating an evaporator/ion exchange based system are less than for other treatment systems such as a filter/ion exchange based system (30, 31).

Based on a station size of 3000 MW, a capital cost of $6.0 million, and an annual operating and maintenance cost at $1.0 million (30, 31) the estimated average annual revenue requirement (AARR) for an evaporator/ion exchange active liquid waste treatment system is 0.076 mills/kWh.

m) Tritium Removal System. The relevant recommendation is:

R212 Consideration of further tritium control.

Levels of annual tritium releases are not specified in R212. However, as in section l) costs have been assessed based on possible state of the art environmental control technologies.

For this analysis the base case assumes the absence of a system for removing tritium from the heavy water in a nuclear station. It is assumed that the tritium removal system will be based on vapour phase catalytic exchange and cryogenic distillation and will be located at the station. It is recognized that other methods are available for tritium control, such as improvements in the leak tightness of heavy water systems (30).

Based on a capital cost of $60.0 million and an annual operating cost of $2.0 million (1981 $ Canadian) (30, 31), the average annual revenue requirement (AARR) for a tritium removal system is estimated at 0.476 mills/kWh (1983 $ Canadian). This cost assumes no credit for the sale of tritium. Also, a system with a liquid phase catalytic exchange may be less costly.

n) Sanitary Wastewater Treatment. The relevant recommendation is:

R213 Segregation and treatment of sanitary wastewater.

For this analysis the assumed base case is the absence of any sanitary wastewater treatment and the direct discharge of sanitary wastewaters to receiving water. For plants built with access to a municipal sewage treatment system, wastes would normally be discharged to that system at a cost lower than that for building and operating a separate treatment facility.

This analysis assumes that secondary biological treatment is provided for sanitary wastewaters. A number of biological treatment systems including rotating biological contactors, oxidation ditches, extended aeration and conventional activated sludge systems are commonly used for this purpose and are capable of producing effluent quality of approximately 20 mg/L BOD_5 and 25 mg/L suspended solids (32). These systems are often available as packaged units of a size suitable for a 1000-MW generating station. Based on a maximum flow of 100 000 m^3/a (appendix E) the maximum average annual revenue requirement for such a system would be .005-.01 mills/kWh (32). Because of economies of scale a unit sized to treat the minimum reported sanitary flow of 5 000 m^3/a (section E) could not be priced on an equivalent basis and the cost is therefore estimated to be approximately 0.001 mills/kWh.

G.3.4 Summary of Cost Estimates. Tables G.15 and G.16 show summaries of the average annual revenue requirements (AARR's) associated with cooling water and wastewater recommendations, respectively. As not all of the AARR's in Tables G.15 and G.16 will apply to any one power generation facility, the total economic impact of the recommendations is determined in the following section by the use of generic models.

G.3.5 Overall Economic Implications

a) Approach. In this section the overall impact of the recommendations is assessed by applying the AARR's developed in Sections G.3.2 and G.3.3 to generic models representing possible future power generation facilities in Canada.

The models chosen for this analysis are the following 1000-MW generating stations:

1) Eastern Canada, coal-fired,
2) Central Canada, coal-fired,
3) Eastern/Central Canada, nuclear,
4a) Western Canada, coal-fired,
 b) Western Canada, coal-fired, zero discharge.

For these models geographical constraints suggest a range of possible plant configurations each of which is a distinct combination of fuel type, coal ash, sulphur, and energy content, proximity to coal source and nature of cooling and process water supply.

TABLE G.15 SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) ASSOCIATED WITH COOLING WATER RECOMMENDATIONS

System Design/Equipment Addition	AARR (mills/kWh)
Recirculating cooling (Fossil Fuel)	
- Cooling Pond	0.04 - 2.56
- Wet Mechanical Draft Tower	0.19 - 1.72
Recirculation Cooling (Nuclear)	
- Cooling Pond	0.08 - 2.79
- Wet Mechanical Draft Tower	0.08 - 2.46
Offshore Submerged Intake with Velocity Cap	0.046 - 0.185
Fish Bypass Facilities	0.003 - 0.089
Offshore Submerged Discharge	0.05 - 0.35
Mechanical Biofouling Control System	0.021 - 0.027
Chlorine Minimization (Once-Through Cooling)	0.005
Dechlorination (Once-Through Cooling)	0.038

These combinations each determine a unique set of base case assumptions and pollution mitigation measures.

In addition to geographical constraints, model assumptions were selected to cover a wide range of probable economic impacts. For example, the central Canada coal-fired plant was designated as one which would have to use recirculating cooling to meet cooling water discharge criteria. This was done to show the higher range of costs, recognizing the possibility that future plants located on a heavily used basin such as Lake Erie might have to adopt such measures. As indicated in Appendix D, Table D.3, however, the cooling potential of many water bodies in central Canada is sufficient that such measures will not be necessary in the near future, provided the once-through cooling system is appropriately located and designed.

b) Assumptions Used as the Basis for the Analysis. The following assumptions are common to all of the coal fired plant models used in this analysis:

Rated Capacity	1000 MW
Capacity Factor	60%
Gross Conversion Efficiency	37%

TABLE G.16 SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) ASSOCIATED WITH WASTEWATER RECOMMENDATIONS

System Design/Equipment Addition	AARR (mills/kWh)
Mechanical Biofouling Control	0.021 - 0.027
Dechlorination of Recirculation Cooling Blowdown	0.005
Replacement of Corrosion Control Chemicals	0.002 - 0.014
Inter. Closed Recirc. Loop Auxiliary Cooling	
- Fossil Fuel	0.01
- Nuclear	0.024 - 0.048
Recirculating Ash Transport and Disposal	0 - 0.56
Closed-loop FGD (forced oxidation systems)	1.05 - 1.23
FGD Sludge Stabilization (natural oxidation systems)	0.77 - 1.86
Wastewater Collection and Containment	0 - 0.002
Seepage Control	0.04 - 1.34
Wastewater Treatment	
- Fossil Fuel	0.274 - 0.297
- Nuclear (non-radioactive discharges)	0.13
Evaporator/Ion Exchange Radioactive Liquid Waste Treatment System	0.076
Tritium Removal System	0.476
Sanitary Wastewater Treatment	0.001 - 0.01

Fly Ash/Bottom Ash	75%/25%
SO_2 Evolved from Sulphur in Coal	92%
FGD Process	Wet Lime Scrubbing
Boiler Type	Pulverized Coal Tangentially Fired
Plant Life	30 years

c) Model 1. Eastern Canada Coal-Fired Generating Station. The following assumptions apply to both the base case and the improved system for Model 1):

Coal Type	Eastern Bituminous
Coal Energy Content	30.2 MJ/kg

Coal Ash Content	8%
Coal Sulphur Content	5.0%
Coal Storage	90 days
Coal Pile Area	4.2×10^4 m^2

The following is an explanation of some of the base case assumptions, system design/equipment additions, and AARR's for Model 1). A summary is given in Table G.17.

Some recently constructed generating stations have been provided with offshore submerged intakes of the velocity cap type for technical reasons not related to environmental protection (33). Although improvements would have to be made to make these sound environmental designs, the incremental cost would not be as high if these were selected as the base case instead of a shoreline intake.

It was assumed that appropriate demonstrations would have been made to permit construction without a fish bypass and return system. However, during the construction of intake facilities provision would be made, at negligible cost, for the addition of fish bypass and return facilities at a later date if required. If fish entrainment was observed to be negligible, the facilities would not be added and the minimum cost would be zero. If bypass and return facilities were needed the maximum cost would be 0.089 mills/kWh as reported in Section G.3.2.

Although the use of chlorine for biofouling control was chosen as the base case, a number of generating stations currently find that they need no chemical biofouling control. Thus, the AARR for chlorine minimization for a new generating facility could be zero. For the same reason, or in the event that a chlorine minimization program was effective in limiting total residual chlorine at the outlet of each condenser to 0.5 mg/L TRC, the AARR for dechlorination could be zero. For both systems the maximum AARR's are as quoted in Section G.3.2.

One report (3) indicates that there is a net saving (incremental AARR -0.27) in dry transport and disposal of ash compared to wet sluicing and pond disposal. This relates primarily to lower capital investment for the disposal area. A number of Canadian generating stations currently use dry fly ash transport and disposal systems. For this analysis it was therefore assumed that the incremental AARR's for dry ash disposal ranged from a low of 0 to the high of 0.56 mills/kWh derived from the Poplar River report.

A forced oxidation FGD system was chosen as the base case because this is currently the type most commonly installed. For Nova Scotia coal the cost of closing the loop for this type of system would be 1.05 to 1.23 mills/kWh. For other Eastern Canada

TABLE G.17 BASE CASE ASSUMPTIONS, SYSTEM DESIGN/EQUIPMENT ADDITIONS, AND INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR MODEL 1), EASTERN CANADA COAL FIRED GENERATING STATION

Base	System Design/Equipment Addition	Incremental AARR (mills/kWh)
Cooling Water		
- Once-through cooling	- No change	
- Shoreline intake	- Offshore submerged intake with velocity cap	0.046 - 0.185
- No fish bypass and return	- Fish bypass and return facilities	0 - 0.089
- Shoreline discharge	- Offshore submerged discharge	0.05 - 0.35
- Chlorine use for biofouling control	- Chlorine minimization	0 - 0.005
	- Dechlorination	0 - 0.038
Wastewater		
- Once-through direct auxiliary cooling	- Intermediate closed recirc. loop auxiliary cooling	0.01
- Once-through wet fly ash and bottom ash transport and pond disposal	- Dry fly ash and dewatered bottom ash transport and landfill disposal	0 - 0.56
- Open-loop forced oxidation FGD	- Closed-loop FGD	1.05 - 1.23
- No containment facilities	- Wastewater collection and containment facilities	0 - 0.002
- No provision for seepage control	- Natural bentonite liner for:	
	Coal Pile (41,750 m^2) @ $8.23/$m^2$	0 - 0.007
	Ash Disposal (5.17 x 10^5 m^2) @ $8.23/$m^2$	0 - 0.081
	FGD Sludge Disposal (1.97 x 10^6 m^2) @ $8.23/$m^2$	0 - 0.308
- No chemical wastewater treatment	- Treatment based on oil separation, lime neutralization and clarification for coal pile runoff, ash transport blowdown, boilers cleaning and boiler blowdown wastewaters	0.274 - 0.297
- No sanitary waste treatment	- Secondary biological sanitary waste treatment	0.001 - 0.01
TOTAL	- All systems	1.43 - 3.17
	- All systems except FGD	0.38 - 1.63

coals the cost of closing the loop would probably be less (18). Because the waste produced would be physically stable no separate cost has been listed for FGD sludge stabilization. If a natural oxidation system were used as the base case sludge stabilization by the sludge/fly ash blending process would cost 0.77 mills/kWh and this would probably also result in a closed process loop.

In a number of areas of this country the natural clay containing soils have permeabilities less than those required for seepage control (the equivalent of 1 metre of material where $K_p = 1 \times 10^{-7}$ cm/s). It is assumed that if a generating station were built on such material no special measures would have to be taken to reduce seepage to groundwater. The minimum AARR for seepage control is therefore assumed to be zero. In calculating the maximum AARR for seepage control for coal piles, ash disposal landfills, and FGD sludge landfills the maximum cost of $8.23/m^2 for a bentonite liner (Table G.11) was used and liner area determined using the following assumptions:

Bulk Density of Coal in Pile	1000 kg/m^3	
Area Required by Coal Pile	1×10^{-5} ha/m^3	*
Volume of Fly and Bottom Ash (30 yr)	3.1×10^6 m^3	ϕ
Ash Landfill Depth	6 m	**
Fly Ash and Bottom Ash Dry Bulk Density	1.44 g/cm^3	ϕ
Volume of FGD Sludge (30 yr)	1.18×10^7 m^3	ϕ
FGD Sludge Landfill Depth	6 m	**
FGD Sludge Dry Bulk Density	0.86 g/cm^3	ϕ

Waste treatment AARR's relate to processes which would be required to meet the wastewater quality criteria of recommendation R211. Processes such as vapour compression evaporation (VCE) and reverse osmosis (RO) were not included because they provide treatment in excess of that required in the recommendation. VCE and RO processes are included in the AARR calculated for the zero discharge plant in model 4 b) because the removal of dissolved solids is assumed to be necessary for total reuse of wastewaters.

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* Appropriate average calculated from reference (26)

ϕ From Table 13, reference (25)

** From reference (3)

d) Model 2. Central Canada Coal-Fired Generating Station. The following assumptions apply to both the base case and the improved system for Model 2).

Coal Type	Eastern Bituminous
Coal Energy Content	27.9 MJ/kg
Coal Ash Content	10%
Coal Sulphur Content	2.0%
Coal Storage	1 year
Coal Pile Area	1.83×10^5 m^2

The following is an explanation of some of the base case assumptions, system design additions, and AARR's for Model 2). A summary is given in Table G.18.

Although the abundance of water sources such as the Great Lakes/St. Lawrence River system may continue to make once-through cooling systems the choice for some future generating facilities in central Canada, recirculating cooling was chosen for this analysis. This was done to show the wide range of possible costs for mitigation measures related to cooling systems. This choice also takes into account the possibility that recirculating cooling systems may in the future be required on some heavily used basins such as Lake Erie, on smaller lake systems, and on river locations such as the Ottawa River.

It has been assumed that the requirement for an intermediate closed loop auxiliary cooling system would not be applicable if a recirculating cooling system were used for both condenser and auxiliary cooling purposes.

Wet mechanical draft towers were chosen for the analysis because there is extensive operating experience with these systems, cost data are relatively abundant, reported costs cover the range of costs for other evaporative cooling systems, and the cost of the cooling system is relatively independent of plant siting. In contrast, cooling pond costs are highly site-specific and dry cooling system costs are very high.

Comments relating to Model 1) regarding ash transport and disposal also apply for Model 2).

Comments relating to Model 1) regarding FGD generally also apply to Model 2) but the cost of closing the loop for the coals typically fired in Central Canada (Ontario) would be 1.1 to 1.18 mills/kWh.

Seepage control costs were calculated in a manner similar to that used for Model 1) but with the following assumptions:

TABLE G.18 BASE CASE ASSUMPTIONS, SYSTEM DESIGN/EQUIPMENT ADDITIONS, AND INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR MODEL 2), CENTRAL CANADA COAL FIRED GENERATING STATION

Base	System Design/Equipment Addition	Incremental AARR (mills/kWh)
Cooling Water		
- Once-through cooling	- Recirculating cooling - wet mechanical draft	0.19 - 1.72
Wastewater		
- Chlorine discharge in recirc. cooling blowdown	- Dechlorination of recirc. cooling blowdown	0 - 0.005
- Use of toxic compounds for corrosion, scaling and silting control	- Replacement of toxic compounds for corrosion scaling and silting control	0.002 - 0.014
- Once-through wet fly ash and bottom ash transport and pond disposal	- Dry fly ash and dewatered bottom ash transport and landfill disposal	0 - 0.56
- Open-loop forced oxidation FGD	- Closed-loop FGD	1.1 - 1.18
- No containment facilities	- Wastewater collection and containment facilities	0 - 0.002
- No provision for seepage control	- Natural bentonite liner for:	
	Coal Pile (183,000) @ $8.16/m^2	0 - 0.029
	Ash Disposal (6.83 x 10^5 m^2) @ $8.16/m^2	0 - 0.106
	FGD Sludge Disposal (7.17 x 10^5 m^2) @ $8.16/m^2	0 - 0.111
- No chemical wastewater treatment	- Treatment based on oil separation, lime neutralization and clarification for coal pile runoff, ash transport blowdown, boiler cleaning and boiler blowdown wastewaters	0.274 - 0.297
- No sanitary wastewater treatment	- Secondary biological sanitary wastewater treatment	0.001 - 0.01
TOTAL	- All systems	1.56 - 4.03
	- All systems except FGD	0.47 - 2.74

Bulk Density of Coal in Pile	1000 kg/m^3	
Area Required by Coal Pile	1×10^{-5} ha/m^3	*
Volume of Fly and Bottom Ash (30 yr)	4.1×10^6 m^3	ϕ
Ash Landfill Depth	6 m	**
Fly Ash and Bottom Ash Dry Bulk Density	1.44 g/cm^3	ϕ
Volume of FGD Sludge (30 yr)	4.3×10^6 m^3	ϕ
FGD Sludge Landfill Depth	6 m	**
FGD Sludge Dry Bulk Density	0.86 g/cm^3	ϕ

Waste treatment calculations were as noted for Model 1).

e) Model 3 Eastern/Central Nuclear Generating Station. The following assumptions apply to the base case and improved systems for Model 3).

Rated Capacity	1000 MW
Capacity Factor	80%
Plant Life	30 Years

The following is an explanation of some of the base case assumptions, system modifications and AARR's for Model 3). A summary is given in Table G.19.

Comments regarding Model 1) costs for offshore submerged intakes, fish bypasses, and chlorine minimization and dechlorination also apply for Model 3).

In a coal-fired station the areas of significance for seepage control include coal piles, ash disposal landfills and FGD sludge disposal landfills. At a nuclear station only the solid active waste storage would require seepage control. Although a seepage control cost is given in Table G.19, the incremental cost associated with these codes of practice is probably negligible because separate seepage control requirements would normally be applied in the licensing at a radioactive waste disposal facility.

It was assumed that chemical (non-radioactive) wastewater treatment for boiler cleaning, boiler blowdown, floor drain, and water treatment wastewaters would be accomplished by a treatment system consisting of equalization, oil separation, chemical precipitation, clarification and filtration. As noted in the discussion for Model 1), it was

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* Appropriate average calculated from reference (26)

ϕ From Table 13, reference (25)

** From reference (3)

TABLE G.19 BASE CASE ASSUMPTIONS, SYSTEM DESIGN/EQUIPMENT ADDITIONS, AND INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR MODEL 3), EASTERN/CENTRAL NUCLEAR GENERATING STATION

Base	System Design/Equipment Addition	Incremental AARR (mills/kWh)
Cooling Water		
- Once-through cooling	- No change	
- Shoreline intake	- Offshore submerged intake with velocity cap	0.046 - 0.185
- No fish bypass and return	- Fish bypass and return facilities	0 - 0.089
- Shoreline discharge	- Offshore submerged discharge	0.05 - 0.35
- Chlorine use for biofouling control	- Chlorine minimization	0 - 0.005
	- Dechlorination	0 - 0.038
Wastewater		
- Once-through direct auxiliary cooling	- Intermediate closed recirc. loop auxiliary cooling	0.024 - 0.081
- No containment facilities	- Minimal requirement for containment	
- No provision for seepage control	- Natural benotnite liner for solid active waste storage area (8100 m^2) @ $8.16/m^2	0.001
- No chemical wastewater treatment	- Treatment based on oil separation, chemical precipitation, clarification, and filtration for boiler cleaning, boiler blowdown, floor drain, and water treatment wastewaters	0.13
- No radioactive liquid waste treatment	- Evaporator/ion exchange active liquid waste treatment system	0.076
- No tritium removal system	- Tritium removal system	0.476
- No sanitary wastewater treatment	- Secondary biological sanitary wastewater treatment	0.001 - 0.01
TOTAL - without RWT		0.25 - 0.89
- with RWT		0.80 - 1.44

RWT (radioactive waste treatment) consists of evaporator/ion exchange wastewater treatment and a tritium removal system assumed that more complex treatment processes such as vapour compression evaporation would not be required to meet the wastewater quality criteria of R211. It was assumed that an evaporator/ion exchange radioactive liquid waste treatment system and a tritium removal system would be installed.

f) Model 4a Western Coal-Fired Generating Station. The following assumptions apply to both the base case and the improved sytem for Model 4).

Coal Type	Western Subbituminous
Coal Energy Content	20.9 MJ/kg
Coal Ash Content	15%
Coal Sulphur Content	0.2%
Coal Storage	30 days
Coal Pile Area	2.01×10^4 m^2

The following is an explanation of some of the base case assumptions, system design/equipment additions, and AARR's for Model 4a). A summary is given in Table G.20.

For many Western Canadian locations and particularly for proposed mine mouth generating stations, limited water supplies preclude the use of once-through cooling systems. A recirculating cooling system was therefore assumed as the base case for this analysis. The base case system would thus meet the recommendations and no incremental AARR would be applicable.

Once-through ash transport systems are not technically feasible at a number of water-short western Canadian locations. The base case for this analysis was therefore assumed to be a wet recirculating combined fly ash and bottom ash transport and disposal system. Dry fly ash and dewatered bottom ash transport and disposal has been used in this analysis to represent the maximum cost (.52 mills/kwh) of mitigating the concerns relating to ash transport wastewater.* The following considerations indicate that the incremental AARR would actually be much lower or negligible:

a) One report (3) indicates tht there is a net saving (incremental AARR = -0.27) in dry transport and disposal of ash compared to wet sluicing and pond disposal.

b) A number of Canadian generating stations currently use dry fly ash transport and disposal sytems indicating that they have been found preferable for technical or economic reasons and do not constitute a significant environmental cost.

TABLE G.20 BASE CASE ASSUMPTIONS, SYSTEM DESIGN/EQUIPMENT ADDITIONS, AND INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR MODEL 4a), WESTERN CANADA COAL FIRED GENERATING STATION

Base	System Design/Equipment Addition	Incremental AARR Mills/kWh
Cooling Water		
- Recirculating cooling system	- No change	
Wastewater		
- Chlorine discharge in recirc. cooling blowdown	- Dechlorination of recirc. cooling blowdown	0 - 0.005
- Use of toxic compounts for corrosion, scaling and silting control	- Replacement of toxic compounds for corrosion scaling and silting control	0.002 - 0.014
- Wet recirculating combined fly ash and bottom ash transport and disposal	- Dry fly ash and dewatered bottom ash transport and disposal by landfill	0 - 0.52
- No FGD system (coal = 0.2% sulphur)	- No FGD system	
- No containment facilities	- Wastewater collection and containment facilities	0 - 0.002
- No provision for seepage control	- Natural bentonite liner for:	
	Coal pile (20,100 m^2) @ $7.24/$m^2$	0 - 0.003
	Ash Disposal (1.38 x 10^6 m^2) @ $7.24/$m^2$	0 - 0.19
- No chemical wastewater treatment	- Treatment based on oil separation, lime neutralization and clarification for coal pile runoff, ash transport blowdown, boiler cleaning and boiler blowdown wastewaters	0.274 - 0.297
- No sanitary wastewater treatment	- Secondary biological sanitary wastewater treatment	0.001 - 0.01
TOTAL		0.28 - 1.04

c) Recirculating combined ash systems have been designed to operate as total recirculation systems and thus no additional cost is incurred in minimizing ash transport wastewater (although additional cost may be incurred in seepage control).

d) The incremental cost of reducing recirculating ash system blowdown to acceptable levels is assumed to be very small.

e) One report (34) indicates that an automatic dewatering bottom ash system (scraper conveyor) is cheaper than alternative wet systems.

It was assumed that the western Canada generating station would burn coal with a sulphur content of 0.2% and therefore would not require a FGD system.

Seepage control costs were calculated in a manner similar to that used for Model 1 but with the following assumptions:

Bulk Density of Coal in Pile	1000 kg/m^3	
Area Required by Coal Pile	1×10^{-5} ha/m^3	**
Volume of Fly and Bottom Ash (30 yr.)	3.1×10^6 m^3	ϕ
Ash Landfill Depth	6 m	***
Fly Ash and Bottom Ash Dry Bulk Density	1.44 g/cm^3	ϕ

Waste treatment cost calculations for Model 4a) were as noted for Model 1).

g) Model 4b Western Canada Coal-Fired Generating Station-Zero Discharge. Model 4b) is the same as Model 4a) but is designed as a zero discharge plant. Although zero discharge will affect many aspects of plant design, it is assumed for this analysis that the major costs will be related to the wastewater treatment system. The wastewater treatment system handles cooling tower blowdown, boiler cleaning and boiler blowdown wastewater, water treatment wastewater, ash transport blowdown, coal pile runoff and floor and yard drainage. The term wastewater treatment system is perhaps a misnomer because the system's primary function is to upgrade process water for reuse. Zero discharge treatment systems described in Table G.14 include reverse osmosis and/or vapour compression evaporation systems.

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* The incremental AARR of 0.52 mills/kWh was calculated from Table G.8 by substracting the AARR for a combined wet recirculating ash transport and disposal system from the AARR for a dry fly ash and dewatered bottom ash system.

** Appropriate average calculated from reference (26)

ϕ From Table 13, reference (25)

*** From reference (3)

The use of a zero discharge system would mitigate most of the concerns associated with the codes of practice recommendations. Thus, as shown in Table G.21, the calculation of the total incremental AARR would contain only a few components.

Although a zero discharge system is not necessary to provide the level of environmental protection expressed in the recommendations, it is worth noting that there is an overlap in the AARR ranges for Models 4a) and 4b). This indicates that in some circumstances a zero discharge system may be economically the most viable environmental control alternative. In addition, other considerations such as high costs for pumping and treating intake water may make zero discharge the preferred system.

h) Summary. One means of assessing the impact of the recommendations would be to compare the total incremental AARR's derived from the models to the total annual costs (capital & fuel & operating) for a new generating facility. Coal-fired generation facility costs from a number of sources, shown in Table G.22, indicate that annual costs for a new 1000-MW facility would vary from 69-133 mills/kWh with FGD included and from 62-121 mills/kWh without FGD. FGD costs were identified because it is possible that some facilities will meet sulphur dioxide discharge standards by means other than FGD (for example coal beneficiation or use of low sulphur coal). Similar data for nuclear generating stations, shown in Table G.23, indicate that annual costs for a new 1000-MW facility would vary from 63 - 101 mills/kWh. Table G.24 shows, for each model, total incremental AARR's as a percentage of annual power generating costs. The data indicate that implementation of the codes of practice recommendations would increase the cost of generating electricity from a new facility by 1.1-5.8 percent for facilities including FGD, 0.2-4.4 percent for facilities not including FGD, and 0.8-2.3 percent for nuclear generating stations. Achieving zero discharge would increase the cost of generating electricity from a new plant by 0.6-6.0 percent. For comparison, a very detailed Japanese paper presented at the 1982 OECD conference in the Netherlands (27) indicates that effluent control costs at coal-fired generating facilities are 1.0% of new power generation costs.

Another means of assessing the economic impact of the recommendations is to relate the total incremental AARR's associated with generation costs, to increases in consumer electricity rates. This is difficult to do, however, because the impact of new generation capacity and costs on a utility grid depends on such factors as existing capacity of the grid, base loads, peak loads, availability, etc. Generally, in Canada a new 1000-MW generating station would add roughly 10-50% to the capacity of most provincial

TABLE G.21 BASE CASE ASSUMPTIONS, SYSTEM DESIGN/EQUIPMENT ADDITIONS, AND INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENTS (mills/kWh, 1983 $ Canadian) FOR MODEL 4b), WESTERN CANADA COAL FIRED GENERATING STATION - ZERO DISCHARGE

Base	System Design/Equipment Addition	Incremental AARR Mills/kWh
Cooling Water		
- Recirculating Cooling System	- No change	0
Wastewater		
- Chlorine discharge in recirc. cooling blowdown	- No discharge of blowdown	0
- Use of toxic compounts for corrosion, scaling and silting control	- No wastewater discharge	0
- Wet recirculating combined fly ash and bottom ash transport and disposal	- No discharge of ash transport water	0
- No FGD system (coal = 0.2% sulphur)	- No FGD system	0
- No containment facilities	- Wastewater collection and containment facilities	0 - 0.002
- No provision for seepage control	- Natural bentonite liner for:	
	Coal pile (20,100 m^2) @ $7.24/$m^2$	0 - 0.003
	Ash Disposal (1.38 x 10^6 m^2) @ $7.24/$m^2$	0 - 0.19
- No chemical wastewater treatment	- Zero discharge water treatment and reuse system based on oil separation, lime-soda softening, precipitation, reverse osmosis and vapour compression evaporation	0.70 - 3.54
- No sanitary wastewater treatment	- Secondary biological sanitary wastewater treatment	0.001 - 0.01
TOTAL		0.70 - 3.74

TABLE G.22 CAPITAL COSTS (1983 $ Canadian) AND OPERATING COSTS (mills/kWh, 1983 $ Canadian) FOR 1000-MW PULVERIZED COAL FIRED GENERATING STATIONS WITH AND WITHOUT FLUE GAS DESULPHURIZATION

Ref.	Year Quoted	FGD	Capital Cost $ Cdn. 1983 x 10^6	Annual Cost mills/kWh 1983 Cdn.	Comments
35	1983	with FGD	780-1200		*Pollution Control = 25-30% of capital cost
36	1982	with FGD	1060-1250	69-81	Pollution Control = 20% of capital cost = 12-14% of annual cost
		without FGD	910-1060	62-73	
27	1981	with FGD	1800-1860	120-133	Pollution Control = 20-22% of capital cost = 16-25% of annual cost
					**Effluent Control= 1% of capital cost = 1% of annual cost
		without FGD	1600-1670	108-121	
37	1977	with FGD	1120-1330	88-115	
		without FGD	970-1080	72-96	

* Pollution control refers to all pollution control facilities including particulate removal and flue gas desulphurization which are the highest cost items.

** Effluent control refers only to water pollution control.

TABLE G.23 CAPITAL COSTS (1983 \$ Canadian) AND OPERATING COSTS (mills/kWh, 1983 \$ Canadian) FOR 1000-MW NUCLEAR GENERATING STATIONS

Ref.	Year Quoted	Capital Cost (\$ Cdn. 1983 x 10^6)	Annual Cost (mills/kWh 1983 Cdn.)
36	1982	1680-2800	63-101
37	1977	1510-2170	97

utility grids. For purposes of simplicity it is assumed for this analysis that a new 1 000-MW generating station would increase the capacity of a provincial utility grid by 25% and therefore the increase in consumer electricity rates would be 25% of the total incremental AARR derived from the model.

Table G.25 shows, for each model, the incremental AARR, the incremental AARR discounted to 25%, and the discounted incremental AARR expressed as a percentage of the consumer electricity rate. The calculation was based on an assumed consumer electricity rate of 40 mills/kWh. This analysis predicts an increase in consumer electricity rates of 0.2 - 2.5% as a result of implementing the codes of practice recommendations.

The above analysis is sensitive to the assumed percentage of the incremental AARR actually applied to consumer electricity rates. The assumption of 25% probably represents the maximum case. If a new generation facility was to increase the capacity of a provincial grid by more than 25% the rationale would probably be that the power would be exported for a number of years and the additional costs would therefore be passed on to consumers outside the province.

TABLE G.24 TOTAL INCREMENTAL AVERAGE ANNUAL REVENUE REQUIREMENT RESULTING FROM THE CODES OF PRACTICE RECOMMENDATIONS, AS A PERCENTAGE OF ANNUAL GENERATION COSTS (mills/kWh, 1983 $ Canadian)

Model	Annual Generation Cost (mills/kWh)	Total Incremental Generation AARR (mills/kWh)	Incremental AARR as Percentage of Annual Generation Cost (%)
To comply with the Codes of Practice Recommendations:			
1) Eastern Canada coal-fired			
- with FGD	69 - 133	1.43 - 3.17	1.1 - 4.6
- without FGD	62 - 121	0.38 - 1.63	0.3 - 2.6
2) Central Canada coal-fired			
- with FGD	69 - 133	1.56 - 4.03	1.2 - 5.8
- without FGD	62 - 121	0.47 - 2.74	0.4 - 4.4
3) Eastern/Central Canada, nuclear			
- without RWT	63 - 101	0.25 - 0.89	0.3 - 1.4
- with RWT	63 - 101	0.80 - 1.44	0.8 - 2.3
4a) Western Canada coal-fired	62 - 121	0.28 - 1.04	0.2 - 1.7
To achieve zero discharge:			
4b) Western Canada coal-fired zero discharge	62 - 121	0.70 - 3.74	0.6 - 6.0

TABLE G.25 INCREMENTAL COST OF THE CODES OF PRACTICE RECOMMENDATIONS TO THE CONSUMER OF ELECTRICITY - (AARR's, mills/kWh 1983 $ Canadian)

Model	Total Incremental Generation AARR (mills/kWh)	Incremental AARR Discounted to 25% (mills/kWh)	Increment in Consumer Rate* (%)
To comply with the Codes of Practice Recommendations:			
1. Eastern Canada, coal-fired			
- with FGD	1.43 - 3.17	0.36 - 0.79	0.9 - 2.0
- without FGD	0.38 - 1.63	0.10 - 0.41	0.2 - 1.0
2. Central Canada, coal-fired			
- with FGD	1.56 - 4.03	0.39 - 1.01	1.0 - 2.5
- withouth FGD	0.47 - 2.74	0.12 - 0.69	0.3 - 1.7
3. Eastern/Central Canada, nuclear			
- without RWT	0.25 - 0.89	0.06 - 0.22	0.2 - 0.6
- with RWT	0.80 - 1.44	0.20 - 0.36	0.5 - 0.9
4a Western Canada, coal-fired	0.28 - 1.04	0.07 - 0.26	0.2 - 0.7
To achieve zero discharge:			
4b Western Canada, coal-fired, zero discharge	0.70 - 3.74	0.18 - 0.94	0.4 - 2.3

* Based on consumer rate of 40 mills/kWh.

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